



4Q 2025

Investor Presentation

December Update



EPNG Mojave Compressor Station

Forward-Looking Statements / Non-GAAP Financial Measures / Industry & Market Data

General – The information contained in this presentation does not purport to be all-inclusive or to contain all information that prospective investors may require. Prospective investors are encouraged to conduct their own analysis and review of information contained in this presentation as well as important additional information through the Securities and Exchange Commission’s (“SEC”) EDGAR system at www.sec.gov and on our website at www.kindermorgan.com.

Forward-Looking Statements – This presentation includes forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements include any statement that does not relate strictly to historical or current facts and include statements accompanied by or using words such as “anticipate,” “believe,” “intend,” “plan,” “projection,” “forecast,” “strategy,” “outlook,” “continue,” “estimate,” “expect,” “may,” “will,” “shall,” and “long-term”. In particular, statements, express or implied, concerning future actions, conditions or events, long term demand for our assets and services; energy demand growth and associated natural gas demand; capital projects, including expected costs, completion timing and benefits of those projects; energy-transition related opportunities, including opportunities related to alternative energy sources; our project backlog; and future operating results such as our expectations for 2026 (including expected financial results, dividends, sustaining and discretionary capital expenditures and our financing and capital allocation strategy) are forward-looking statements.

Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. There is no assurance that any of the actions, events or results of the forward-looking statements will occur, or if any of them do, what impact they will have on our results of operations or financial condition. Because of these uncertainties, you are cautioned not to put undue reliance on any forward-looking statement. We disclaim any obligation, other than as required by applicable law, to publicly update or revise any of our forward-looking statements to reflect future events or developments.

Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. These statements are necessarily based upon various assumptions involving judgments with respect to the future, including, among others: commodity prices; the timing and extent of changes in the supply of and demand for the products we transport and handle; trends expected to drive new natural gas demand for electricity generation; changes in tariffs and trade restrictions, including potential adverse effects on financial and economic conditions; national, international, regional and local economic, competitive, political and regulatory conditions and developments; the timing and success of business development efforts; the timing, cost, and success of expansion projects, including potential impacts of tariffs; our ability to consummate and recognize the anticipated benefits of acquisitions; technological developments; the condition of capital and credit markets; inflation rates; interest rates; the political and economic stability of oil-producing nations; energy markets; federal, state or local income tax legislation; changes in policies affecting foreign trade and taxation, including tariffs, and potential adverse effects on financial and economic conditions; weather conditions; environmental conditions; business, regulatory and legal decisions; terrorism; cyber-attacks; and other uncertainties. Important factors that could cause actual results to differ materially from those expressed in or implied by forward-looking statements include the risks and uncertainties described in this presentation and in our Annual Report on Form 10-K for the year ended December 31, 2024, and our subsequent reports filed with the SEC (under the headings “Risk Factors,” “Information Regarding Forward-Looking Statements” and elsewhere). These reports are available through the SEC’s EDGAR system at www.sec.gov and on our website at www.kindermorgan.com.

GAAP – Unless otherwise stated, all historical and estimated future financial information included in this presentation has been prepared in accordance with generally accepted accounting principles in the United States (“GAAP”).

Non-GAAP – In addition to using financial measures prescribed by GAAP, we use non-generally accepted accounting principles (“non-GAAP”) financial measures in this presentation. Descriptions of our non-GAAP financial measures, and reconciliations to comparable GAAP measures, can be found in this presentation under “Non-GAAP Financial Measures and Reconciliations”. These non-GAAP financial measures do not have any standardized meaning under GAAP and may not be comparable to similarly titled measures presented by other issuers. As such, they should not be considered as alternatives to GAAP financial measures.

Industry & Market Data – Certain data included in this presentation has been derived from a variety of sources, including independent industry publications, government publications and other published independent sources. Although we believe that such third-party sources are reliable, we have not independently verified, and take no responsibility for, the accuracy or completeness of such data.

2026 Guidance

Robust Natural Gas Market Fundamentals Supporting Sustained Growth and Attractive Investment Opportunities

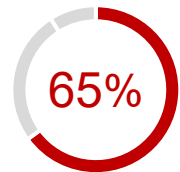
Key Metrics	2026 Budget	Variance to 2025 Forecast	
Adjusted EPS	\$1.37	+8%	Increase driven primarily by continued execution on expansion projects in our Natural Gas segment
Adjusted EBITDA	\$8.65 billion	+4%	
Discretionary Capital ^(a)	\$3.4 billion	+\$0.4 billion	Includes ~\$2.6bn of infrastructure projects at an EBITDA multiple of <6x and ~\$0.7bn of G&P & CO ₂ EOR projects at attractive returns
Dividend / Share	\$1.19	+2%	9 th consecutive annual increase
Year-End Net Debt / Adjusted EBITDA	3.8x	-0.1x	In the lower half of our 3.5x – 4.5x leverage target range Provides capacity for additional opportunistic investment

Note: Adjusted EPS, Adjusted EBITDA, and Net Debt are non-GAAP measures. See Corporate Items and Non-GAAP Financial Measures & Reconciliations. 2026 budget assumes commodity prices of \$60/bbl WTI and \$3.60/mmbtu Henry Hub.

a) Includes growth capital & JV contributions for expansion capital & net of partner contributions for our consolidated JVs.

Irreplaceable Infrastructure Portfolio

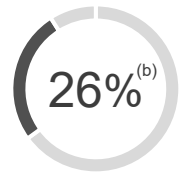
NATURAL GAS



Largest U.S. Natural Gas Transmission Network^(a)

- ~58,500 miles of transmission & ~7,500 miles of gathering pipelines
- Transport ~40% of U.S. natural gas production
- Interest in over 700 bcf of working storage capacity, ~15% of U.S. capacity

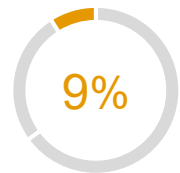
REFINED PRODUCTS



Largest U.S. Independent Refined Products Transporter & Terminal Operator

- Transport ~1.7 mmbbl of refined product volumes
- ~9,500 miles of refined products & crude pipelines
- 139 liquids & bulk terminals; 16 Jones Act vessels
- 135 mmbbl of total liquids storage capacity

CO₂



One of the Largest CO₂ Transporters in the U.S.

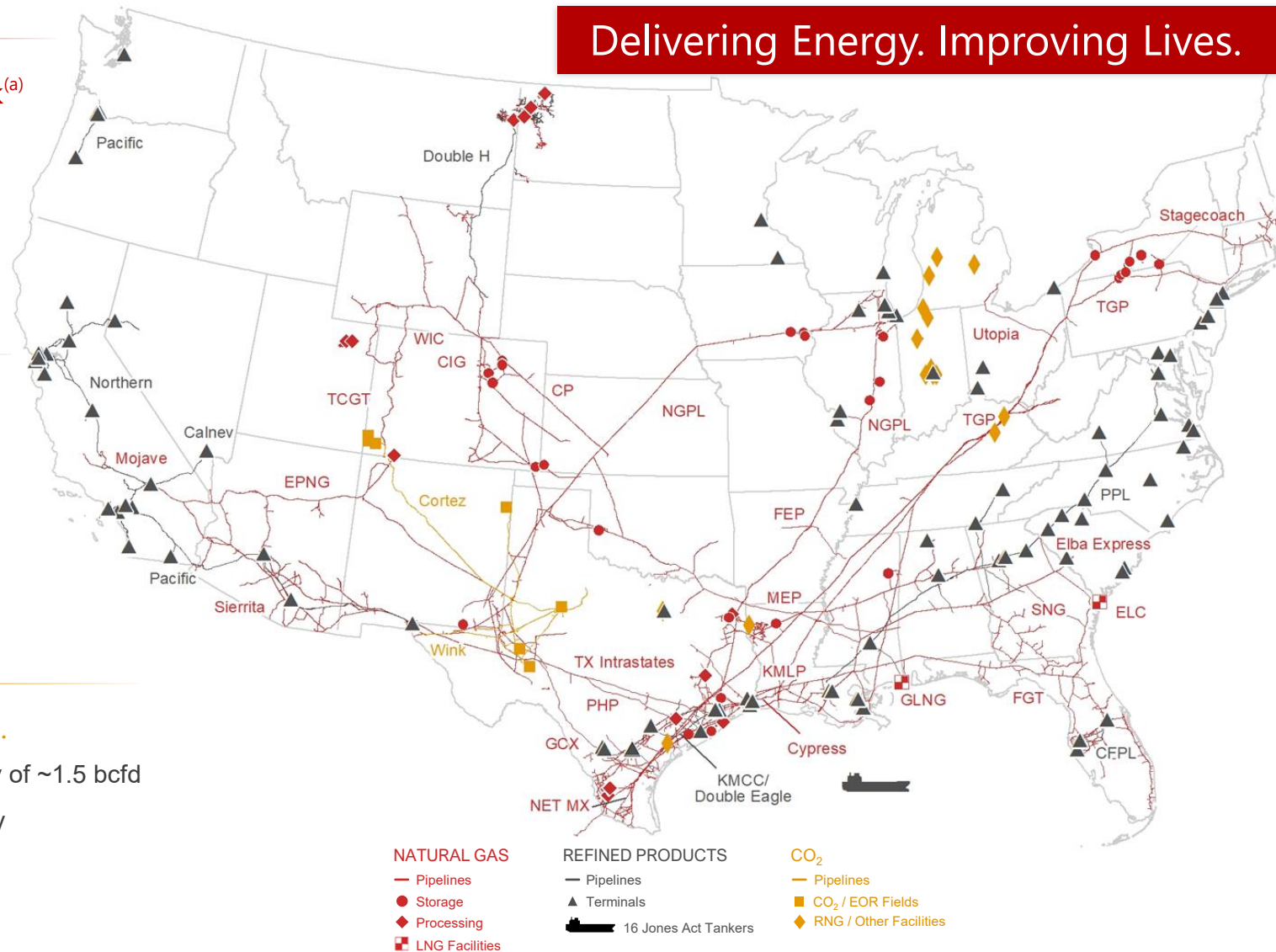
- ~1,500 miles of CO₂ pipelines with transport capacity of ~1.5 bcfd
- Produce and transport CO₂ for enhanced oil recovery

Strategic Energy Transition Portfolio

- RNG production capacity of 6.4 bcf^(c)

BUSINESS MIX

Delivering Energy. Improving Lives.



Note: Volumes per 2025 budget. Business mix based on 2025 budgeted Total Adjusted Segment EBDA, which is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations.

a) Does not include mileage associated with natural gas gathering assets.

b) Refined Products includes 13% from our Products Segment and 13% from our Terminals Segment.

c) Annual capacity at KMI share.

Driving Long-Term Shareholder Value



Natural Gas Focus

~**2/3** of cash flows come from midstream natural gas^(a)

Transport ~**40%** of U.S. natural gas production



Balance Sheet Strength

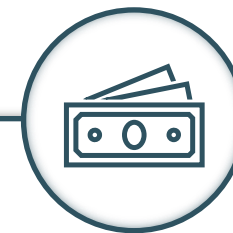
~**3.8x** YE 2025B Net Debt / Adjusted EBITDA^(b)

BBB (positive) / BBB+ investment grade balance sheet^(c)



High-Returning Growth Projects

~**\$9.3 billion** of committed projects at **<6x** EBITDA build multiple



Predictable & Growing Cash Flows

~**69%** of cash flows are take-or-pay or hedged^(a)

+10% Adj. EPS and **+4%** Adj. EBITDA growth budgeted in 2025^(b)



Returns to Shareholders

Increasing dividend for **8th** straight year

~**39%** of market cap value returned to shareholders since 2016^(d)

Note: Total Adjusted Segment EBITDA, Adjusted EPS, Adjusted EBITDA, Net Debt, and EBITDA build multiple (calculated based on Project EBITDA) are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations.

a) Based on 2025 budgeted Total Adjusted Segment EBITDA.

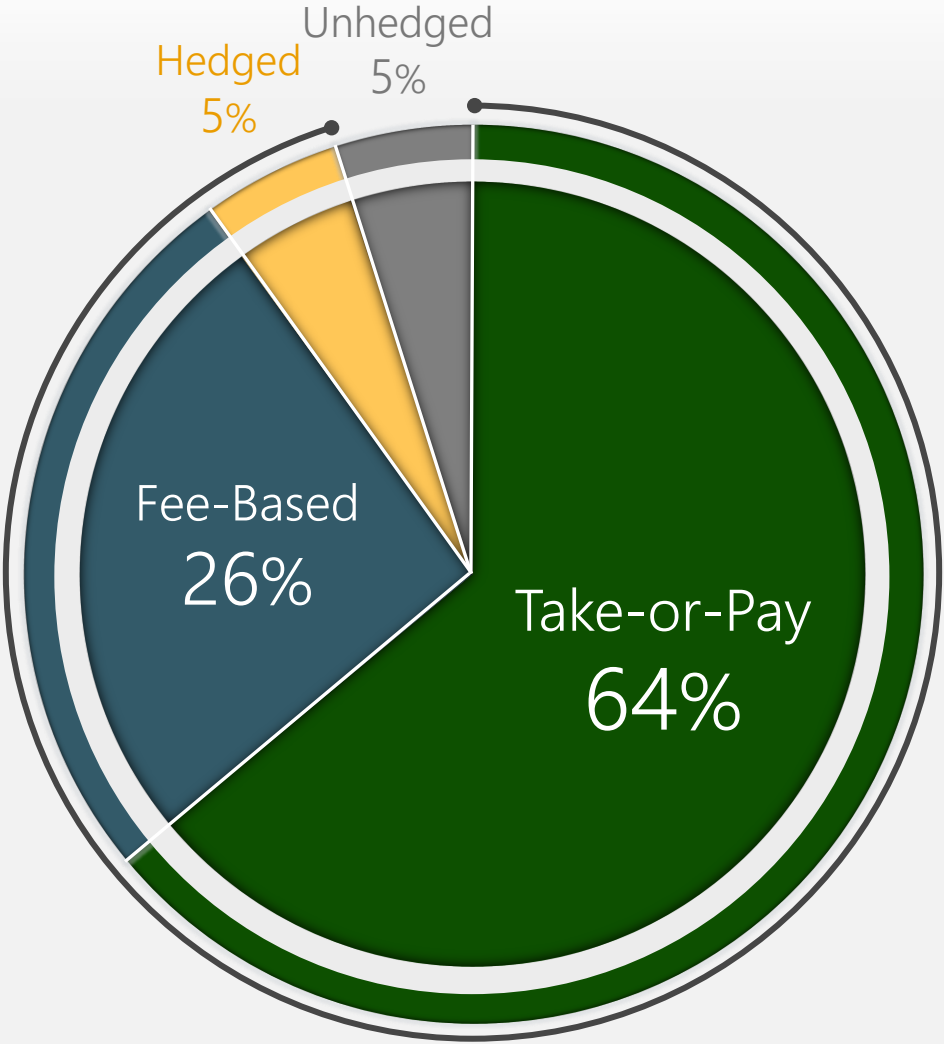
b) 2025 budget does not include contributions from Outrigger Energy II acquisition.

c) Fitch has KMI's senior unsecured rating at BBB+. Moody's and S&P have KMI's senior unsecured rating at Baa2 and BBB, respectively, and both have the rating on positive outlook.

d) Market capitalization as of 10/24/2025. Returns via dividends paid and share repurchases.

Highly Contracted, Predictable Cash Flows

CASH FLOW MIX



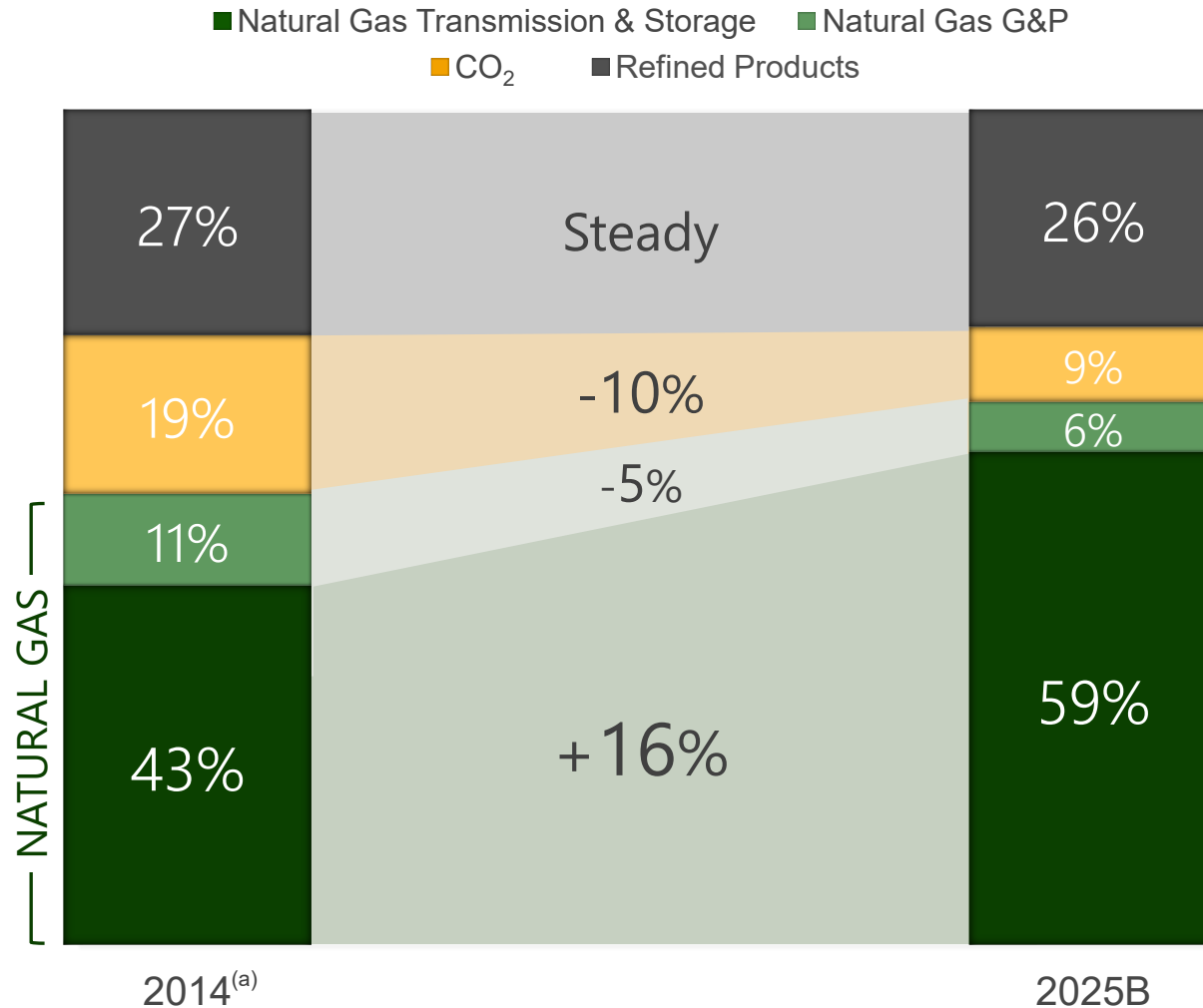
95% Take-or-Pay, Fee-Based, or Hedged Cash Flows

- 64% Take-or-Pay**
Entitled to payment regardless of throughput
Reservation fee for capacity
- 26% Fee-Based**
Fixed fee collected regardless of commodity price
Volumetric based revenues
Over 40% highly stable refined product cash flows
- 5% Hedged**
Disciplined approach to managing price volatility
Substantially hedged near-term price exposure
- 5% Unhedged**
Commodity price based

Note: Cash flow mix based on 2025 budgeted Total Adjusted Segment EBDA, which is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations.

Strong Business Mix Continues to Improve

BUSINESS MIX



CHANGES SINCE 2014

Natural Gas Transmission & Storage increased +16%

Natural Gas G&P decreased -5%

CO₂ reduced -10%

Refined Products - Stable

Note: Business mix based on Total Adjusted Segment EBDA, which is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations. Refined Products includes contributions from Products Pipelines and Terminals segments, as well as KM Canada in 2014. 2014 amounts are adjusted to reflect categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change.

a) First year of combined KMI.

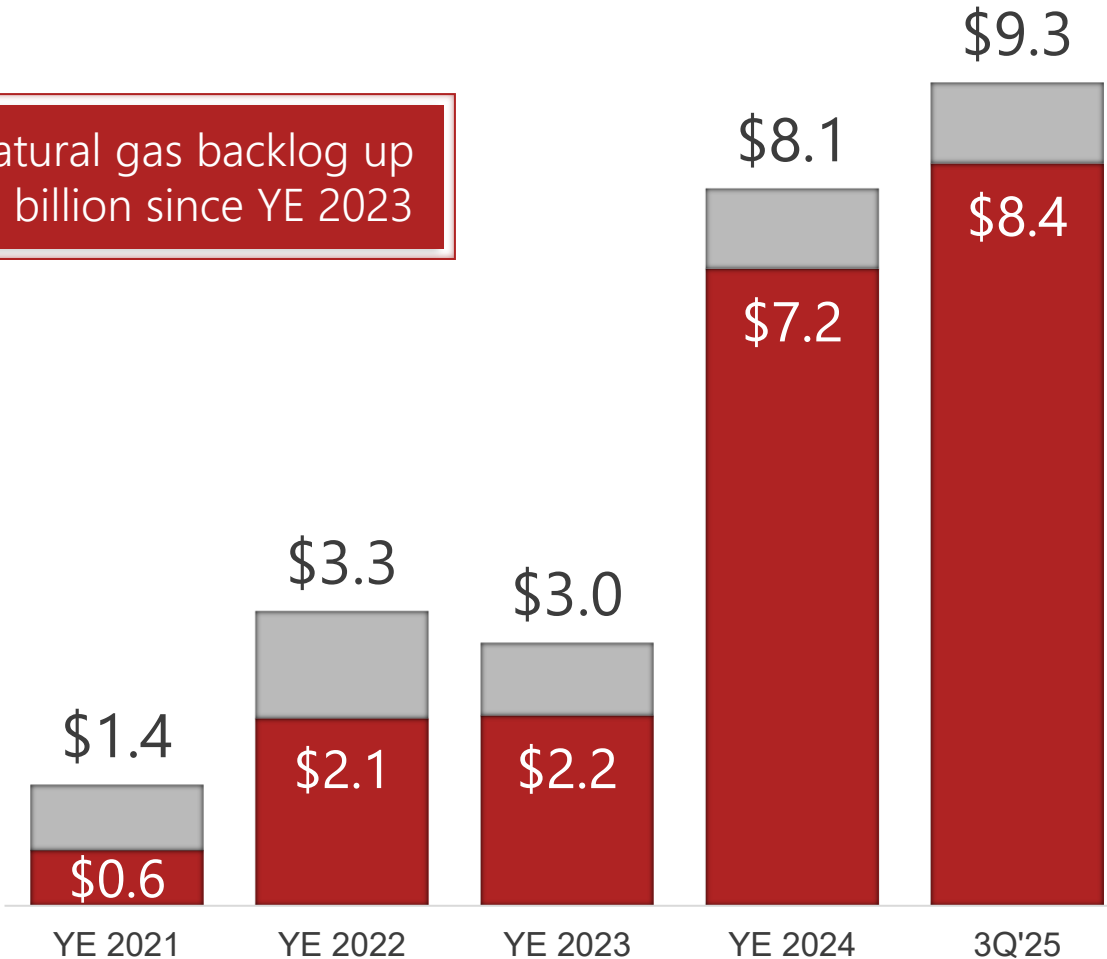
Growing Our Project Backlog While Maintaining Discipline on Returns

PROJECT BACKLOG OVER TIME^(a)

\$ Billion

■ Natural Gas Segment ■ Other Segments

Natural gas backlog up
+\$6.2 billion since YE 2023



Expansive footprint creates opportunities for differentiated returns

Every project must meet **disciplined return criteria** before being added to the backlog

Utilize a **consistent return framework**

Adjust return threshold based on each project's individual risk profile; in all cases, returns are **well in excess of our cost of capital**

Current ~\$9.3 billion project backlog being constructed at <6x EBITDA build multiple

Note: EBITDA build multiple reflects KMI share of estimated capital divided by estimated Project EBITDA (a non-GAAP financial measure). See Non-GAAP Financial Measures & Reconciliations.

a) Project backlog figures are net of projects placed in service.

\$9.3bn Committed Growth Capital Project Backlog as of 9/30/2025

~20% of Backlog Capital in Service Between 4Q 2025 and 2026

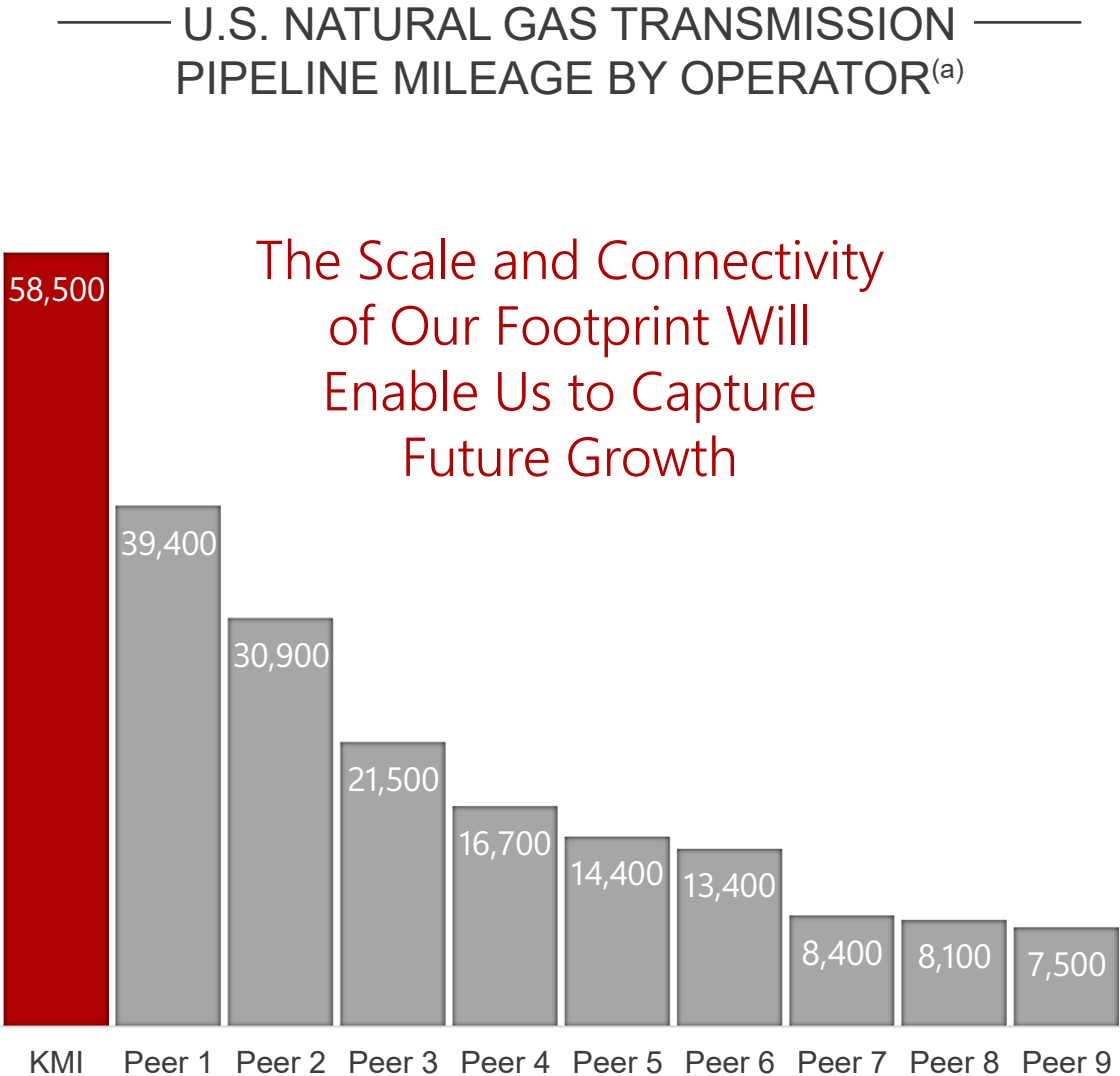
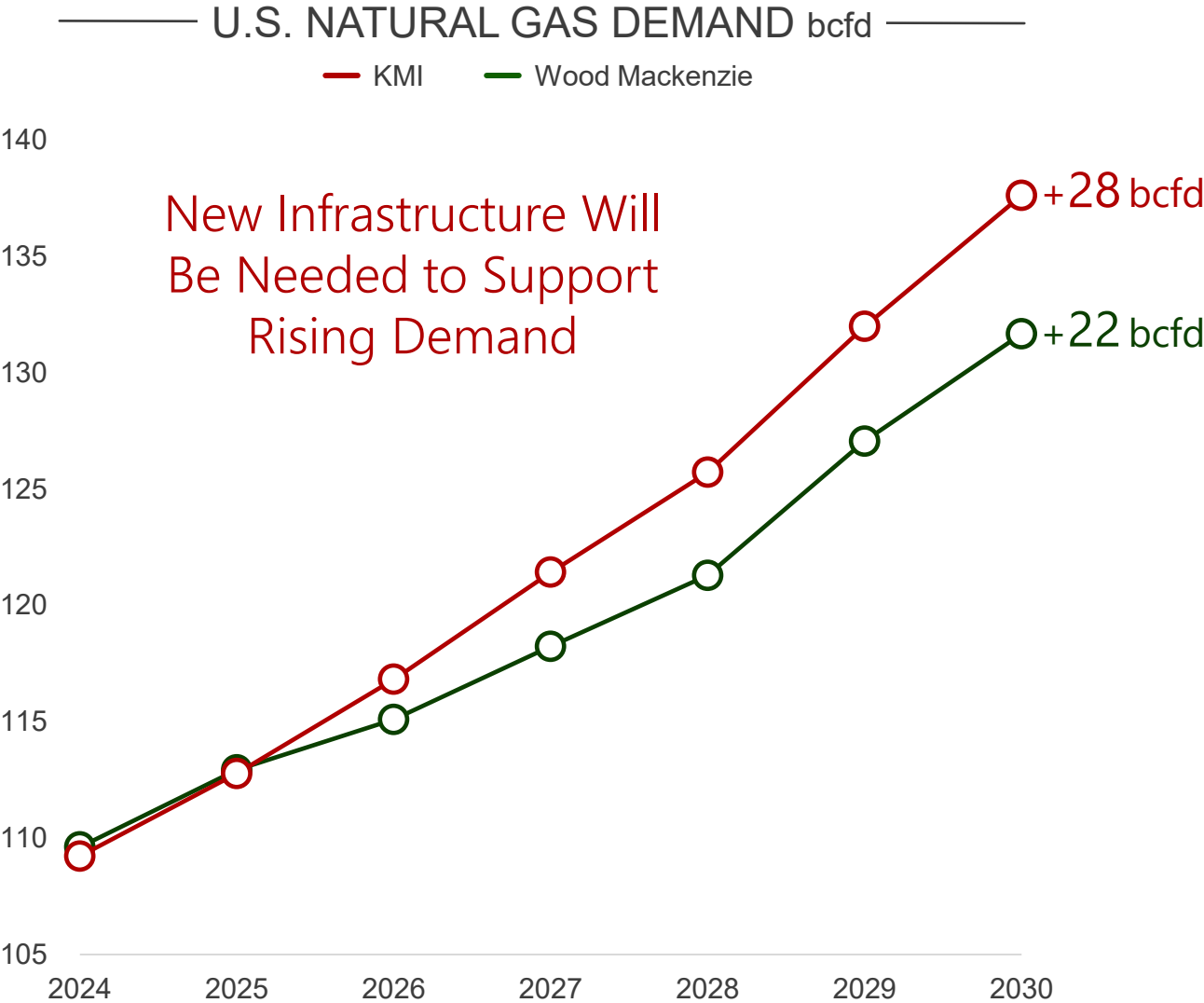
\$ million	TOTAL	
Natural Gas (excluding G&P)	\$7,566	Nearly all serving Power, LDC, and LNG demand
Other	363	Primarily refined product projects
Subtotal	\$7,929	Contracted, stable cash flows, minimal direct commodity exposure
EBITDA Build Multiple	~5.7x	
Gathering & Processing	849	Mostly natural gas, volume-based projects
EOR	530	Commodity price & volume-based cash flows
Total Backlog	\$9,309	

>\$3 billion expected annual growth capex over next few years

Natural gas investments ~90% of backlog

Note: The EBITDA build multiple reflects KMI share of estimated capital divided by estimated Project EBITDA (a non-GAAP financial measure). See Non-GAAP Financial Measures & Reconciliations. Figures may not sum due to rounding. Other includes projects in our Products and Terminals segments and ETV group.

Extensive Network Well-Positioned to Serve Growing U.S. Natural Gas Demand



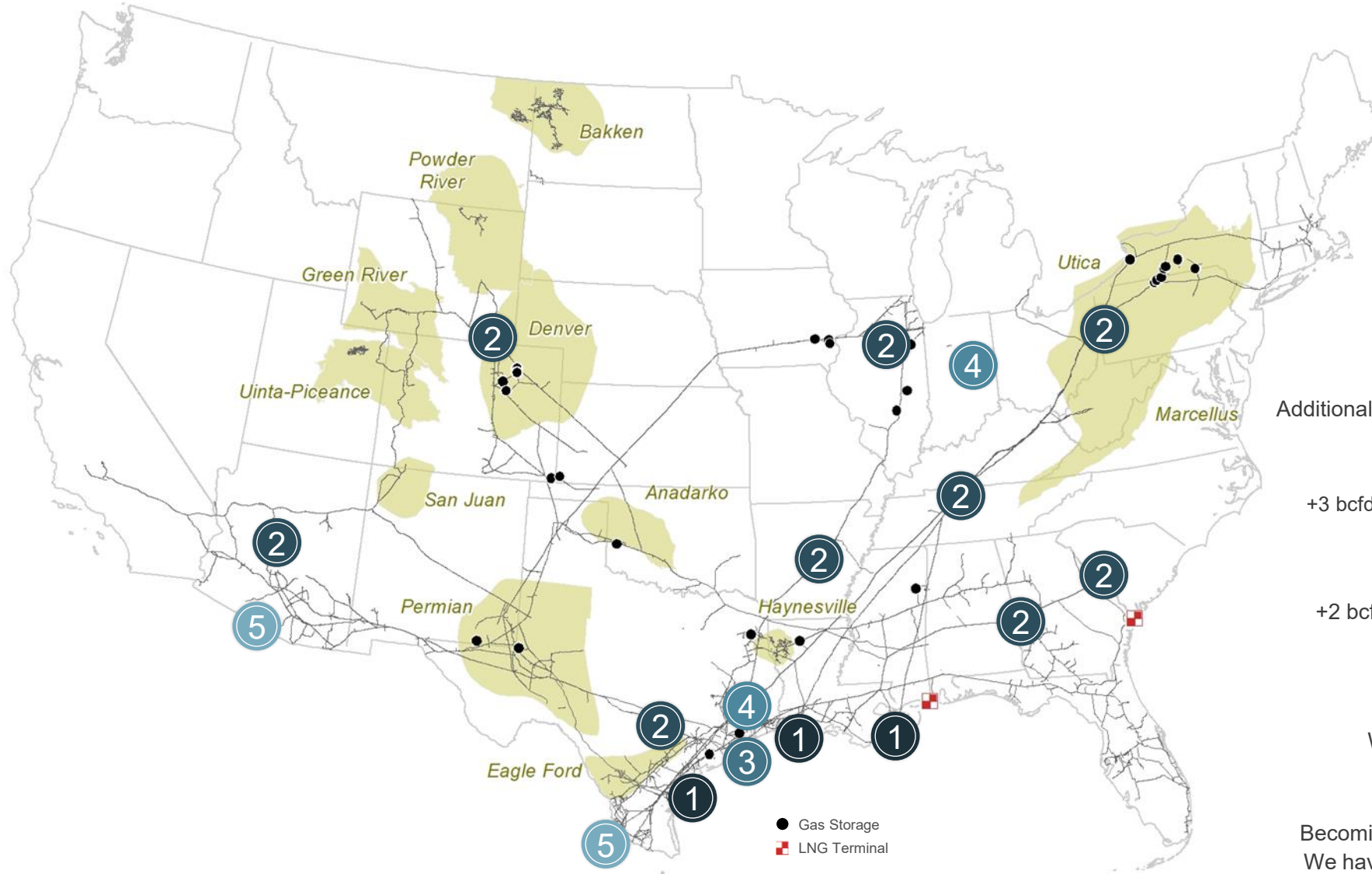
Source: KMI internal natural gas forecast as of 2Q 2025. Wood Mackenzie North America Gas Strategic Planning Outlook, April 2025.
a) Data per company reports and presentations. Does not include mileage associated with gathering assets. Peers include Berkshire, Boardwalk, ENB CN, EPD, ET, OKE, Tallgrass, TRP CN, and WMB.

WoodMac Natural Gas Demand Overview: 2024 – 2030

~85% of Growth is Expected to Occur in Texas & Louisiana, Driven by LNG Exports & Industrial



2024 U.S. Demand
110 bcf/d
Increase in demand by 2030
+22 bcf/d



LNG Feedgas ①

+15 bcf/d of Gulf Coast demand growth
Well positioned to grow our deliveries over time

Power Demand ②

Population and economic growth
Coal retirements/coal-to-gas conversions
Manufacturing re-shoring & data centers
Additional capacity needed to backstop intermittent renewables

Industrial Demand ③

+3 bcf/d of demand growth mainly along the TX & LA Gulf Coast

Residential & Commercial ④

+2 bcf/d of growth, primarily in the Southern U.S. & Midwest

Mexico Exports ⑤

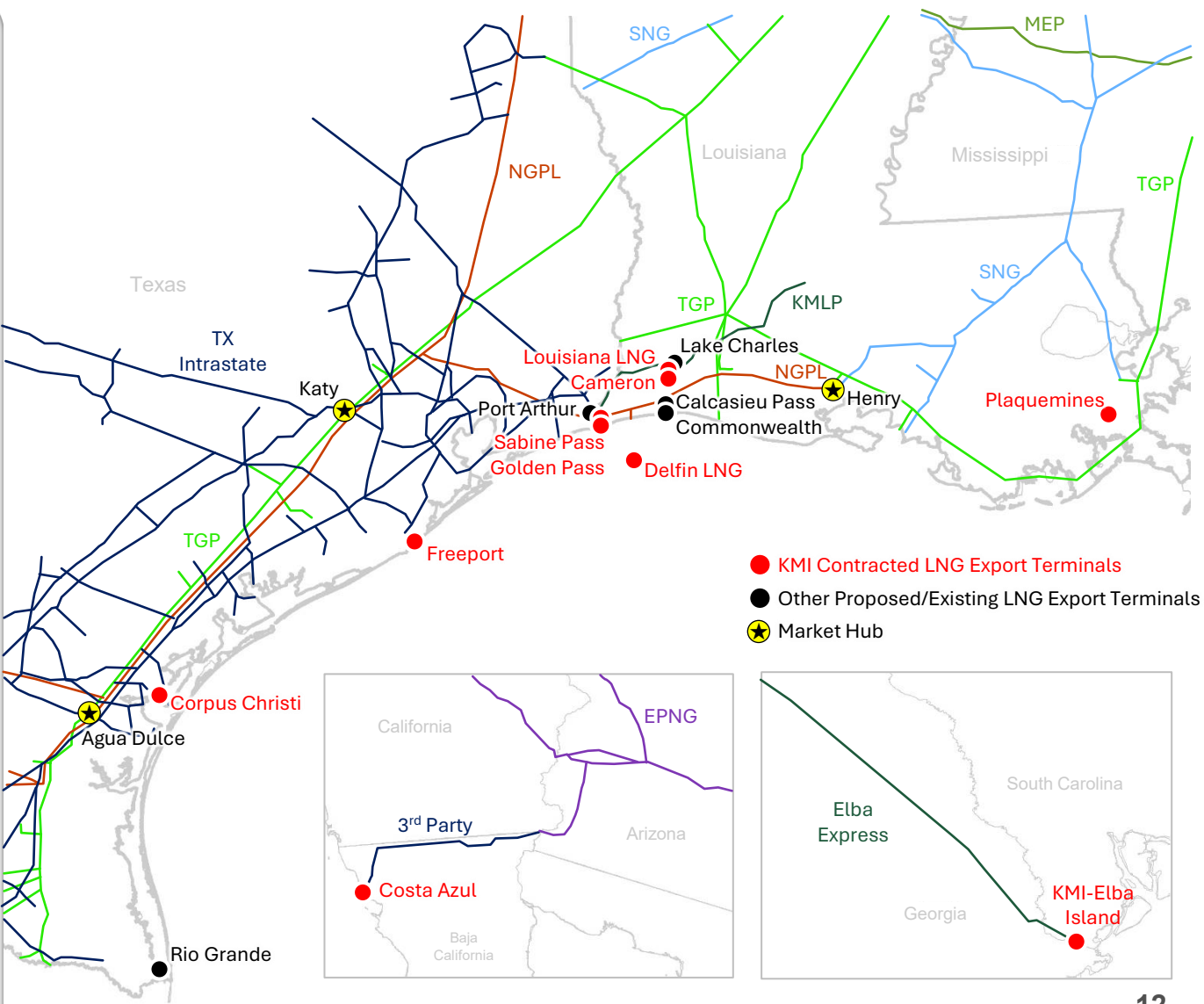
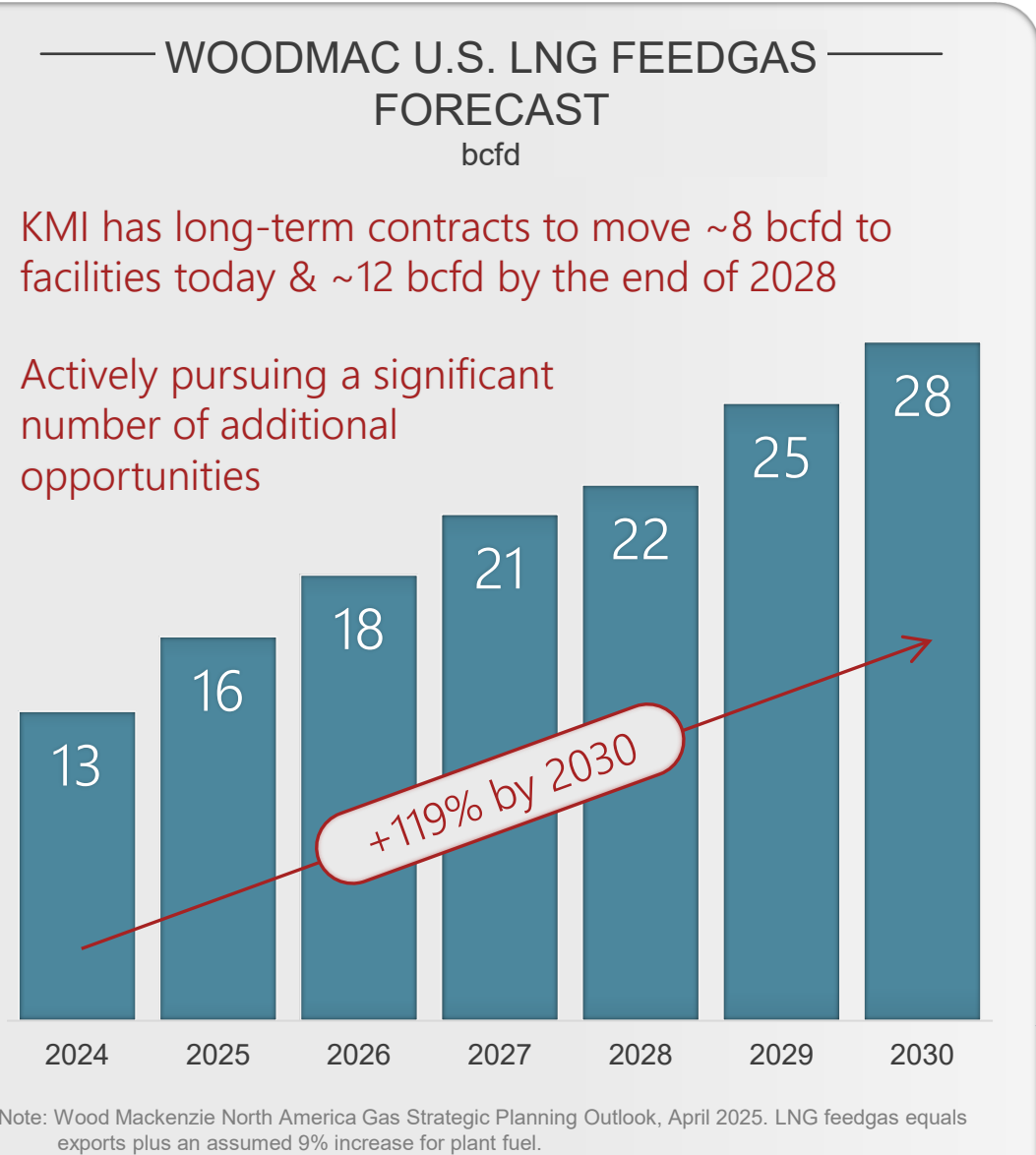
+1 bcf/d of export demand growth
We can deliver into Mexico at multiple strategic points

Storage

Becoming increasingly important to support variable demand
We have interest in over 700 bcf of working storage capacity

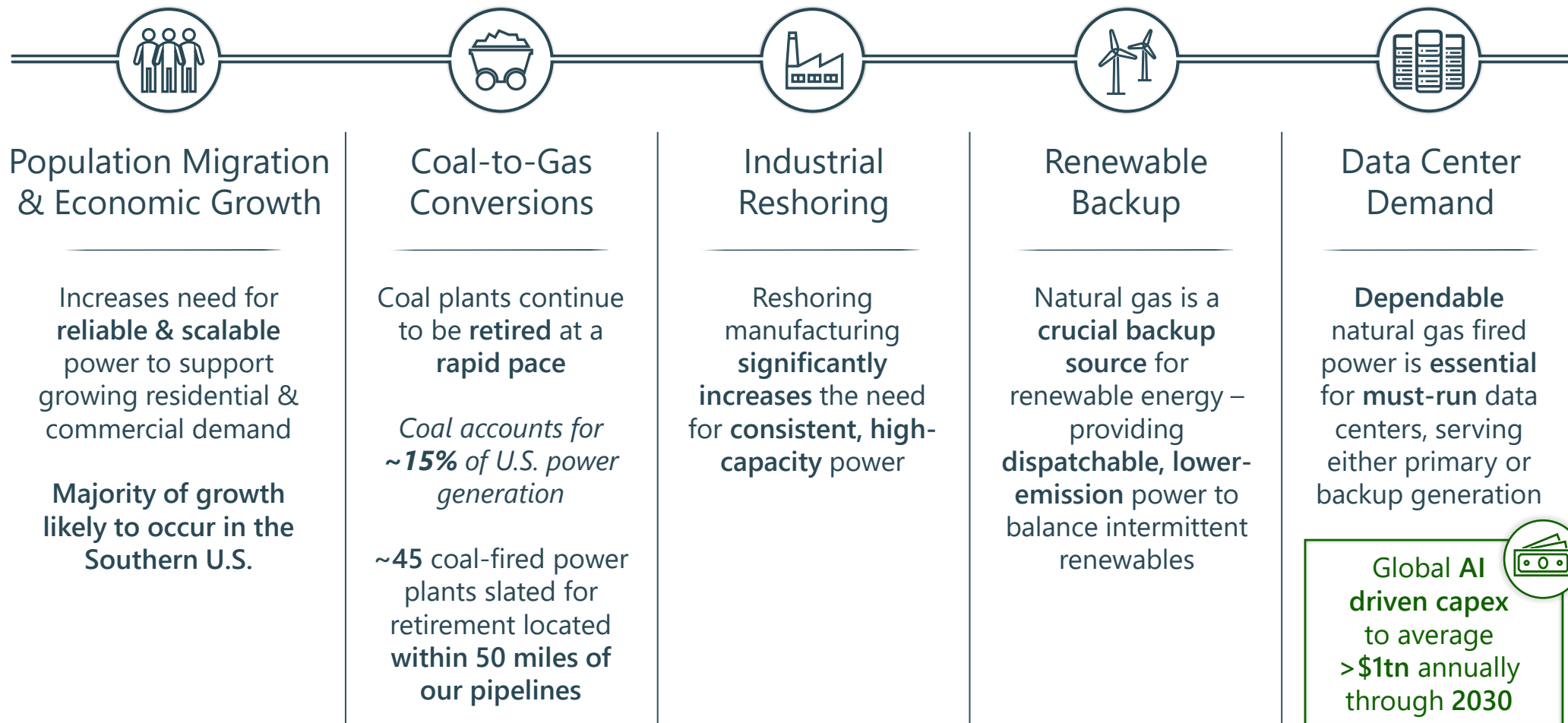
LNG Exports Driving Natural Gas Demand Growth

Growth Primarily Along the Texas & Louisiana Gulf Coast with Great Overlap with Our Assets



Growing Power Needs Boosting Demand for Natural Gas

INCREASING NATURAL GAS FIRED POWER DEMAND DRIVEN BY



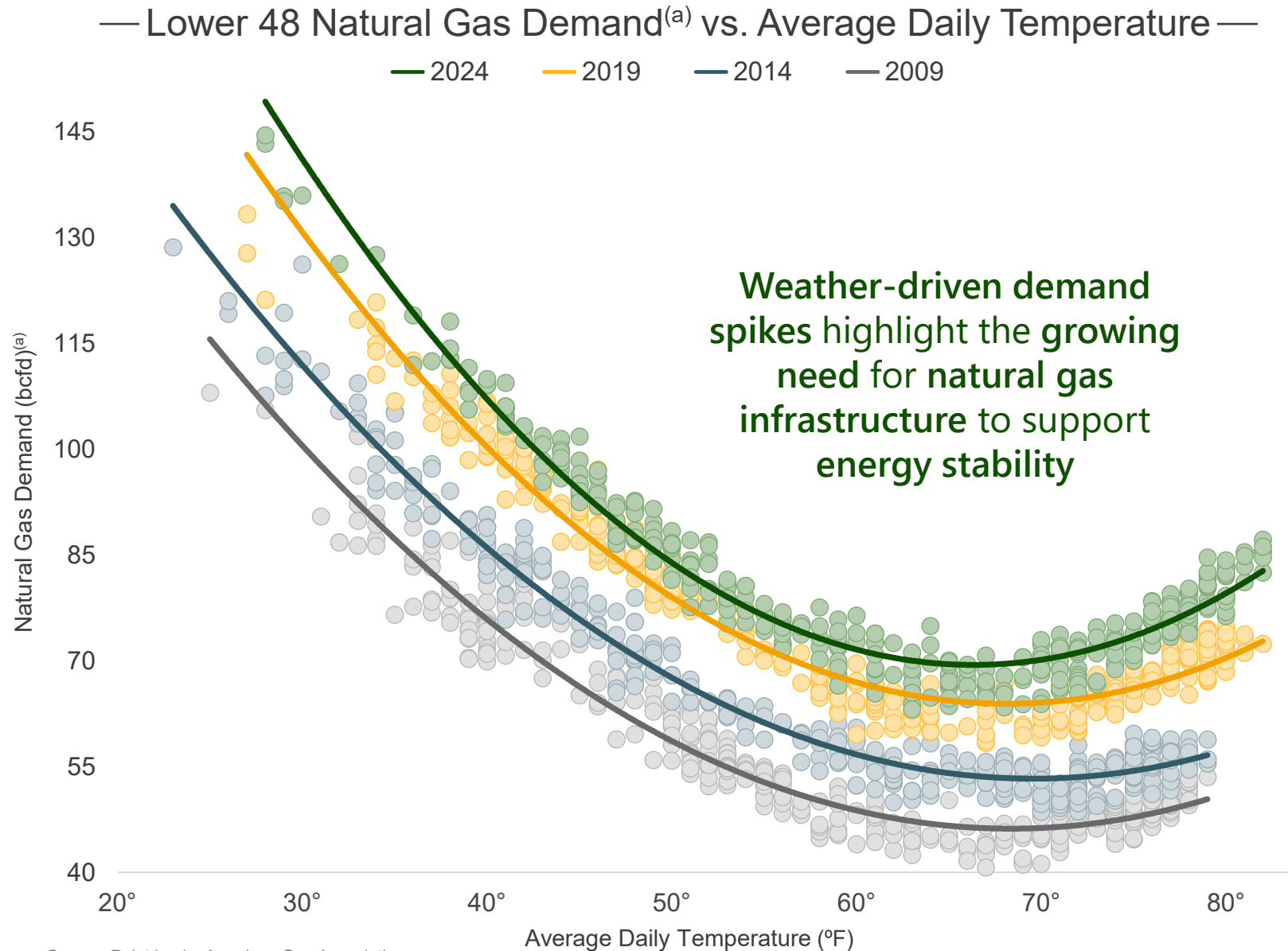
>50% of contracted \$9.3bn project backlog directed to power generation & utility demand

Substantial customer interest for additional capacity

Actively pursuing over 10 bcfd of new power opportunities

Rising Power Demand Not Yet Fully Captured in Many Natural Gas Projections

Rising Need for Natural Gas Amid Growing Market Volatility



Natural gas demand for a given degree day continues to increase

Increasingly variable demand leads to greater spikes in demand

The top 2 all-time record days for natural gas demand occurred in January 2025

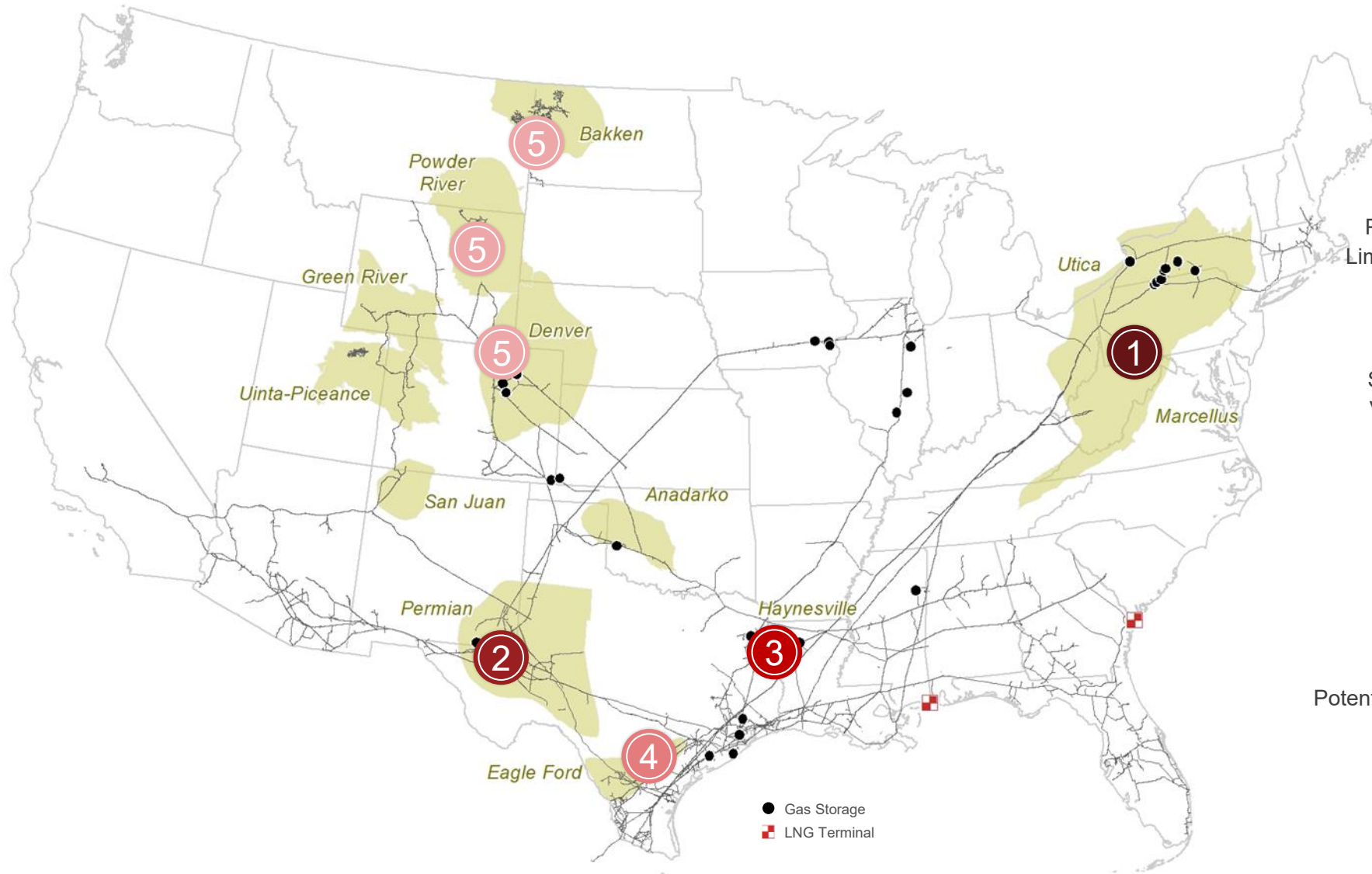
Volatility at both ends of the demand curve is expected to rise

Additional investment in natural gas pipelines and storage will be needed to help meet rising demand and ensure reliability

WoodMac Natural Gas Supply Overview: 2024 – 2030



2024 U.S. Production
103 bcf/d
Increase in supply by 2030
+22 bcf/d



Northeast +7 bcf/d from the Marcellus/Utica **1**

Production constrained despite ample, low-cost supply
Limited infrastructure opportunity despite strong demand

Permian +7 bcf/d of associated gas growth **2**

Supply grows as oil production increases & GORs rise
Vital to supplying West Coast, Gulf Coast, and Mexico

Haynesville +6 bcf/d of growth **3**

Abundant, low-cost, low-nitrogen supply
Key to serving Gulf Coast demand markets

Eagle Ford^(a) +1 bcf/d of growth **4**

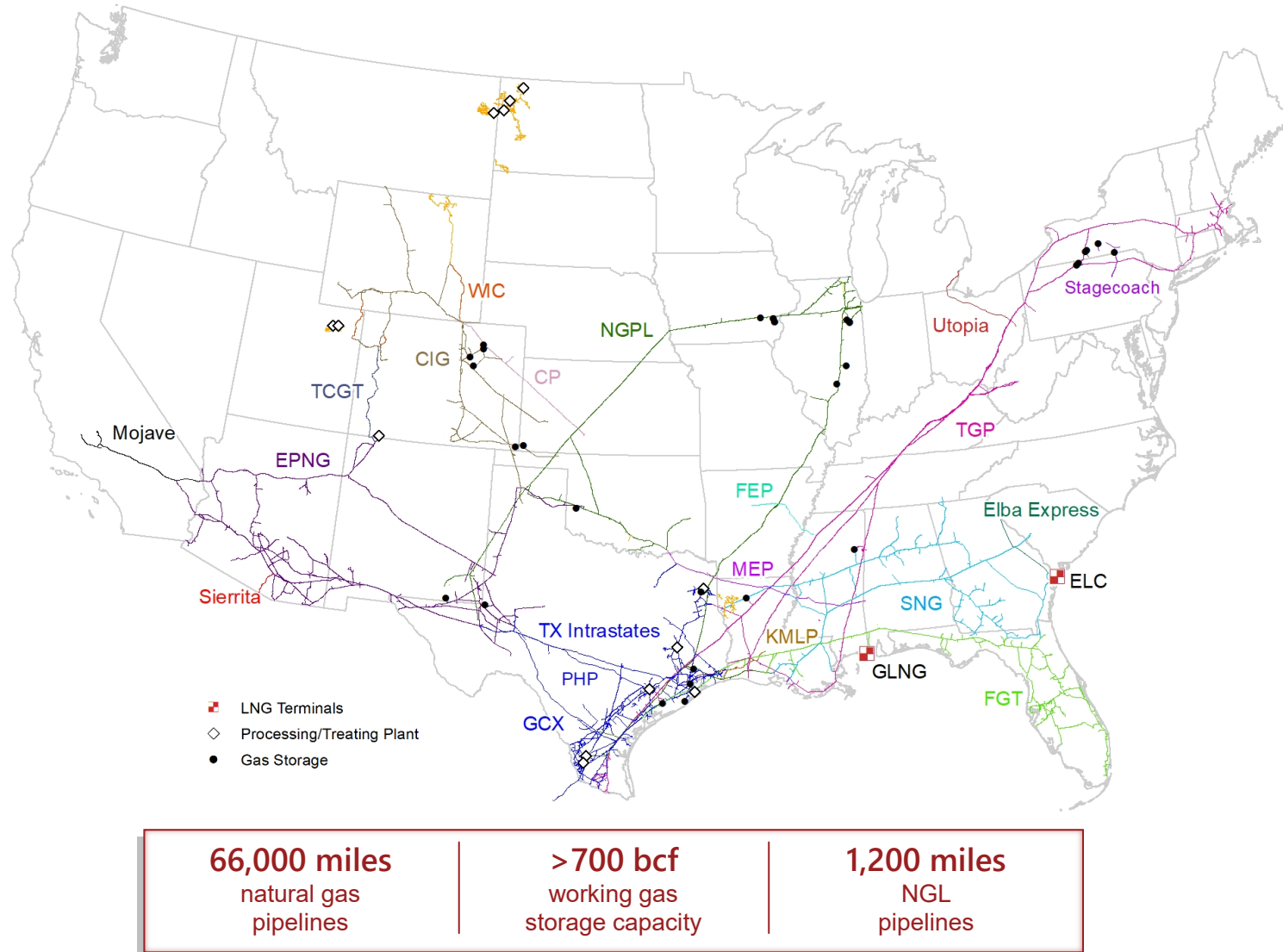
Potential upside to forecast; critical supply link to Gulf Coast
Important source of low-nitrogen gas for LNG facilities

Rockies +1 bcf/d Bakken/DJ/Powder River **5**

Serves Rockies and West Coast demand

Natural Gas Segment Overview

Connecting Key Natural Gas Resources with Major Demand Centers



a) Does not include mileage associated with natural gas gathering assets.

b) Includes deliveries in Arizona, New Mexico, Texas, Arkansas, Louisiana, Tennessee, Mississippi, Alabama, Georgia, and Florida.

Largest Natural Gas Transmission Network in the U.S.^(a)

KMI Transports ~40% of U.S. Natural Gas Production

~45%
of all feedgas deliveries to U.S. LNG facilities

~50%
of all U.S. natural gas exports to Mexico

~45%
of all direct natural gas deliveries to Southern U.S. power plants^(b)
Areas with high forecasted natural gas fired power demand growth

Irreplaceable Assets

Long-Lived Infrastructure

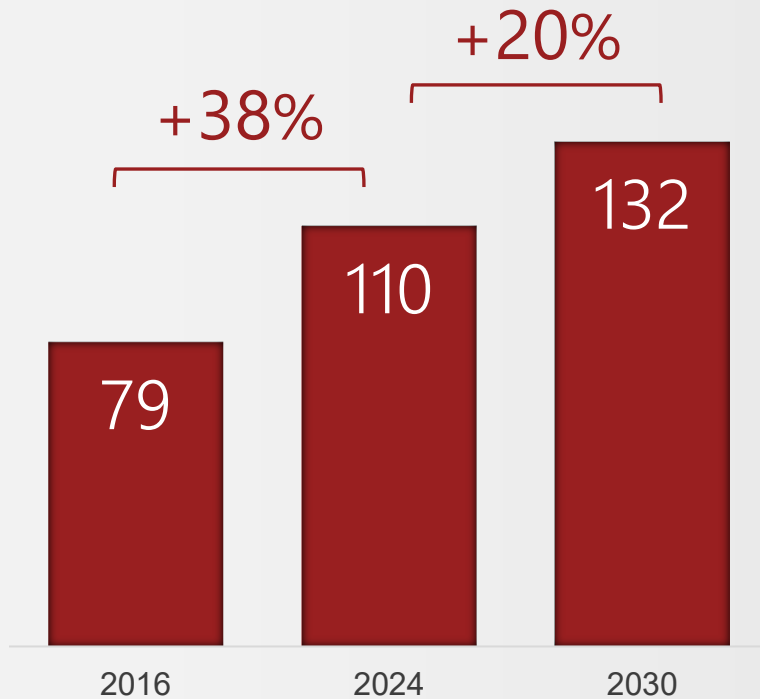
Principally Transmission & Storage Assets, with Gathering & Processing Assets in Key Basins

Robust Opportunity Set for Growth

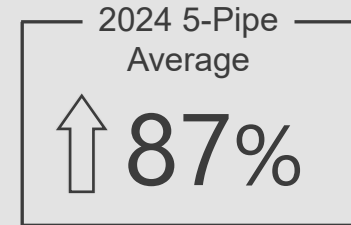
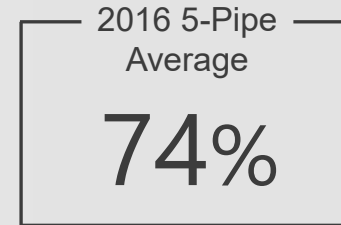
Rising Demand Benefitting Our Natural Gas Transportation Business

Increased Demand Leading To

WOODMAC
U.S. NATURAL GAS DEMAND
bcfd

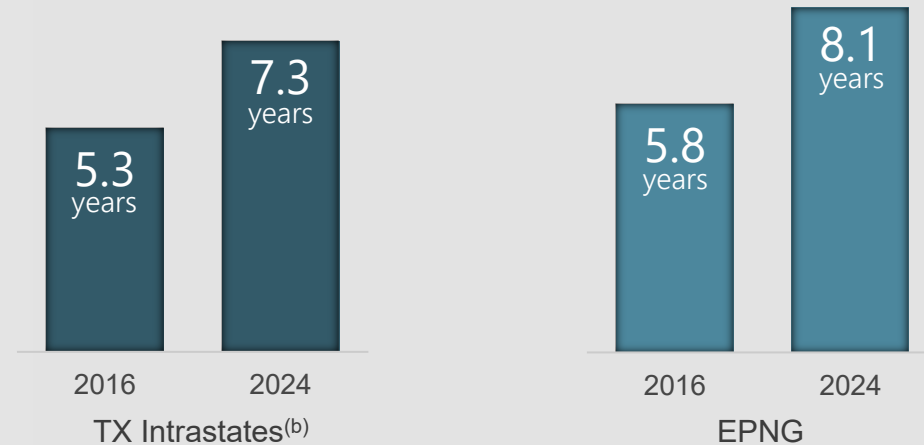


• INCREASED PIPELINE USAGE FACTOR^(a)



• INCREASED CONTRACT TERMS AND/OR RATES

EXAMPLES



• NEW PROJECTS

~\$8.4 billion of natural gas projects in our backlog;
expect to continue adding projects over time^(c)

Source: Wood Mackenzie North America Gas Strategic Planning Outlook, April 2025.

a) Represents the capacity weighted average usage factor of TGP, EPNG, NGPL, SNG, and the Texas Intrastates. Usage factor is calculated as billed throughput divided by average annual designed pipeline capacity.

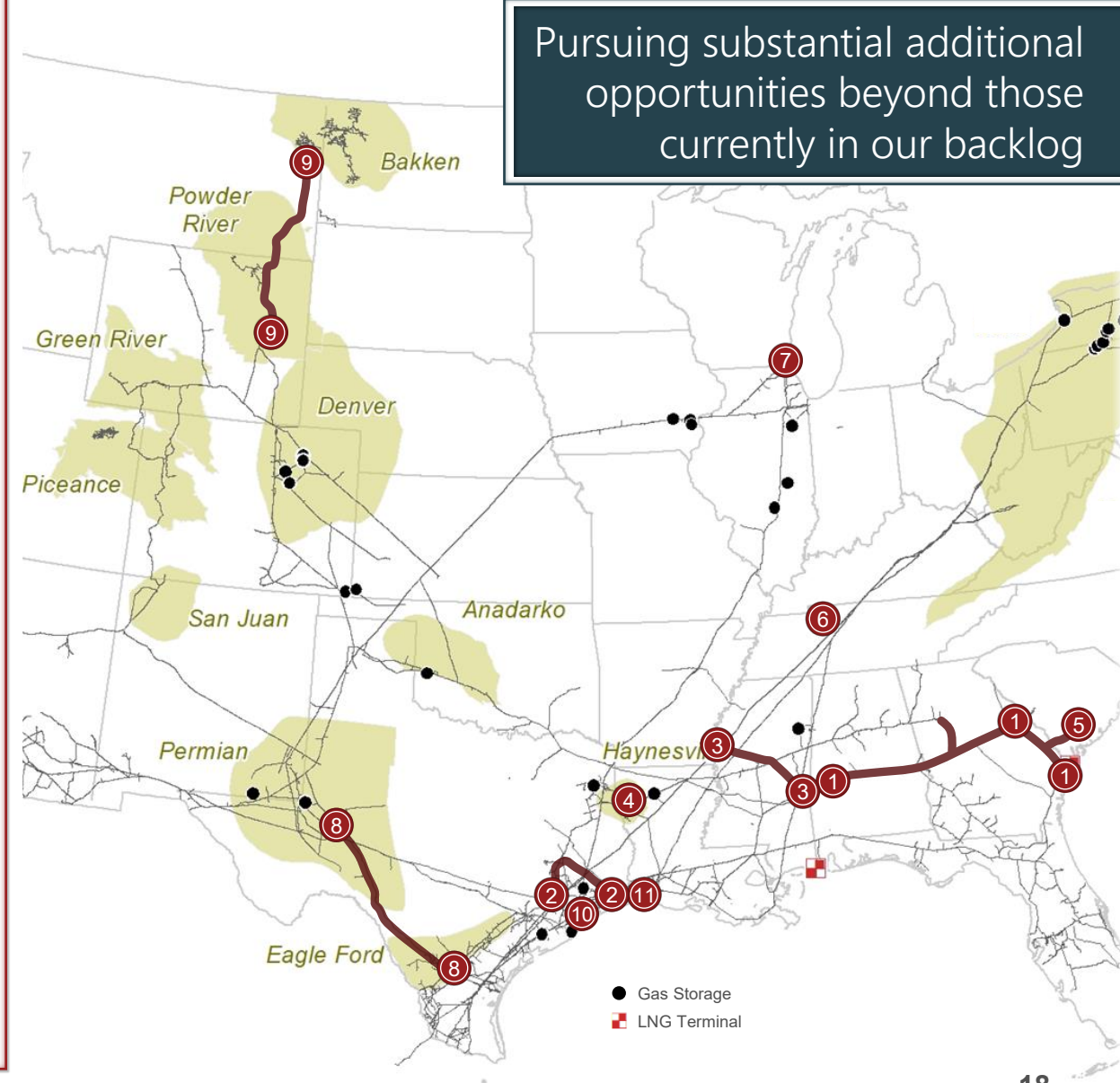
b) TX Intrastates average remaining contract life includes term sale portfolio.

c) Total includes ~\$0.8bn of natural gas gathering & processing projects.

~\$8.4 Billion of Approved Natural Gas Projects

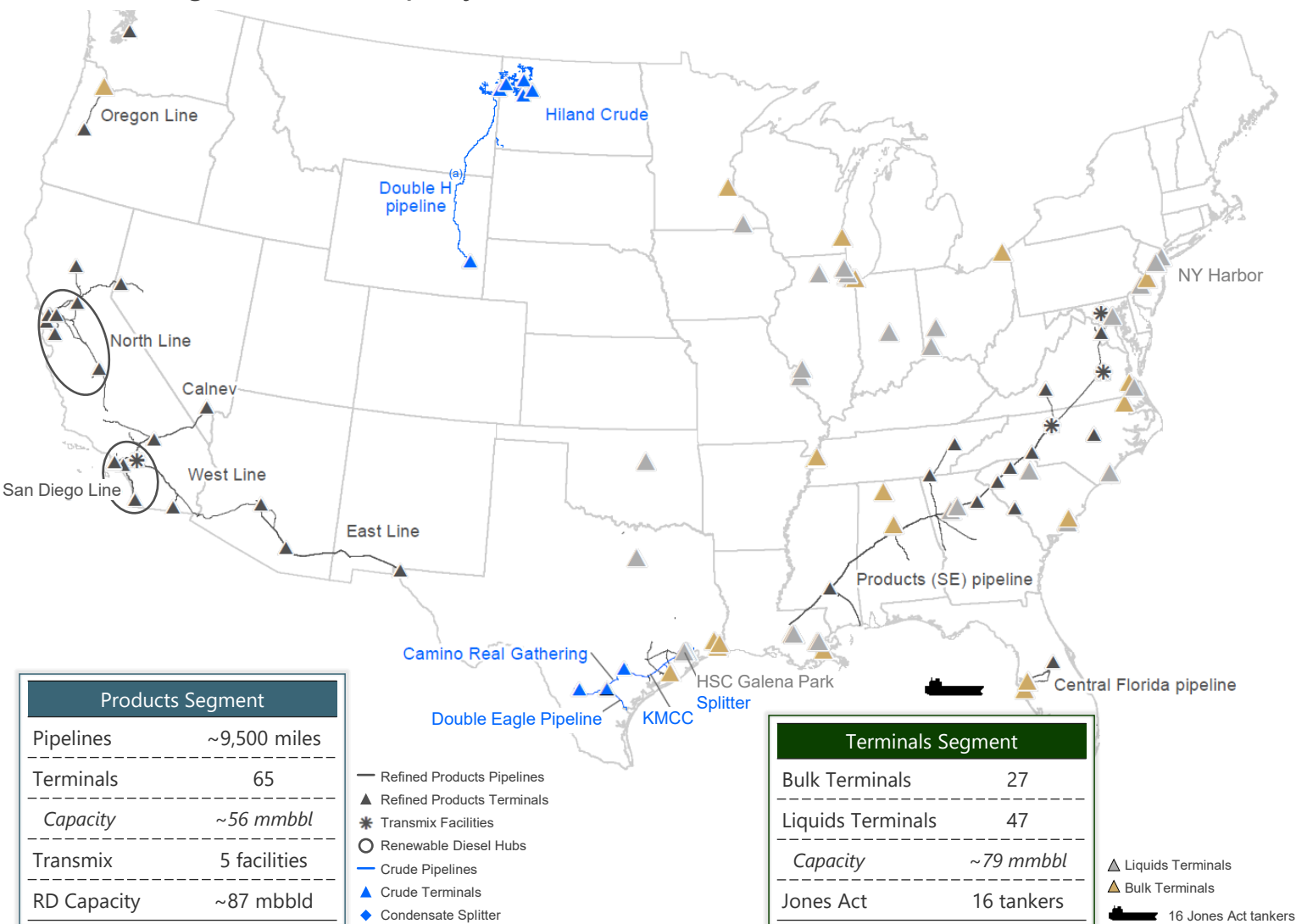
Major Projects	Capital ^(a) (\$bn)	Capacity (bcfd)	In-Service Date	Primary Driver
① South System Expansion 4 <i>SNG & EEC</i>	\$1.8	1.3	4Q28, 4Q29	Power
② Trident (Phase I & II) <i>TX Intrastates</i>	\$1.8	2.0	1Q27, 4Q28	LNG
③ Mississippi Crossing <i>TGP</i>	\$1.7	2.1	4Q28	Power
④ Plantation North Expansion <i>KinderHawk</i>	\$0.5	1.0	4Q26	G&P
⑤ Bridge <i>EEC</i>	\$0.4	0.3	2Q30	Power
⑥ Cumberland <i>TGP</i>	\$0.2	0.2	1Q26	Power
⑦ North Extension <i>NGPL</i>	\$0.2	0.2	4Q28	Power
⑧ GCX Expansion <i>TX Intrastates</i>	\$0.2	0.6	2Q26	Supply Push
⑨ Hiland Express <i>Double H</i>	\$0.1	--	1Q26	NGL Conversion
⑩ Houston Power Generation <i>TX Intrastates</i>	\$0.1	0.7	2Q27, 2Q28	Power
⑪ Texas Access Project <i>KMLP</i>	\$0.1	1.0	4Q28	LNG

a) KMI share of estimated project capital.



Products Segment & Terminals Segment Overview

Both Segments Principally Refined Products Focused



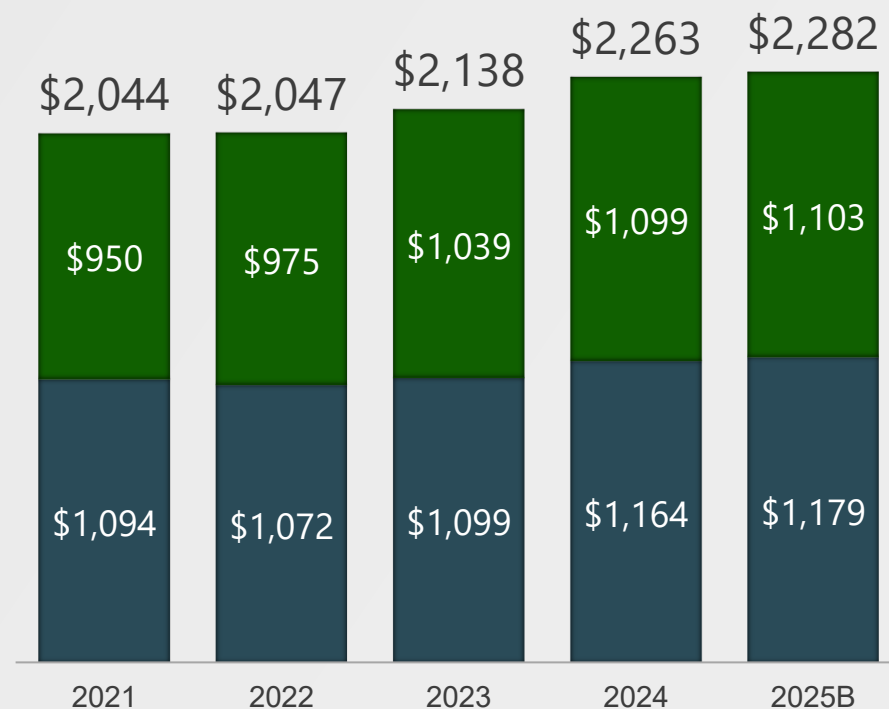
Note: Adjusted Segment EBDA and Terminals and Product Pipelines FCF are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations. 2021 – 2024 Adjusted Segment EBDA amounts are adjusted to reflect categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change.

a) Double H is being converted to NGL service, expected to be in service near the end of Q1 2026.

Nearly \$11bn of Adjusted Segment EBDA & \$8bn of FCF Generated Over 5 Years

— TERMINALS & PRODUCTS PIPELINES —
ADJUSTED SEGMENT EBDA
\$ Millions

■ Products Segment ■ Terminals Segment



CO₂ Segment: EOR and CO₂ Transport Overview

World Class, Fully-Integrated Assets Consistently Generating Robust Free Cash Flow

Interest in 3 oil fields with 8.8 billion barrels of Original Oil In Place

Interest in 3 CO₂ fields with 37 tcf of Original Gas In Place

~1,500 miles of CO₂ pipelines with capacity to move up to 1.5 bcfd



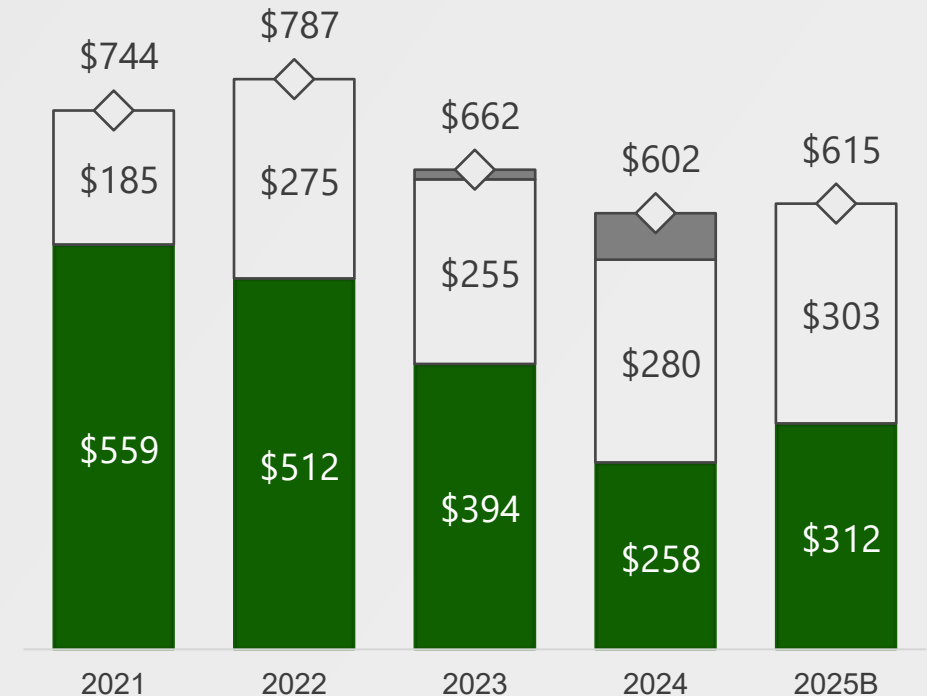
Note: CO₂ EOR & Transport FCF and Adjusted Segment EBDA are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations. 2021 – 2024 Adj. Segment EBDA amounts are adjusted to reflect categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change. SACROC includes Diamond M acreage.

a) Includes sustaining and expansion capital expenditures.

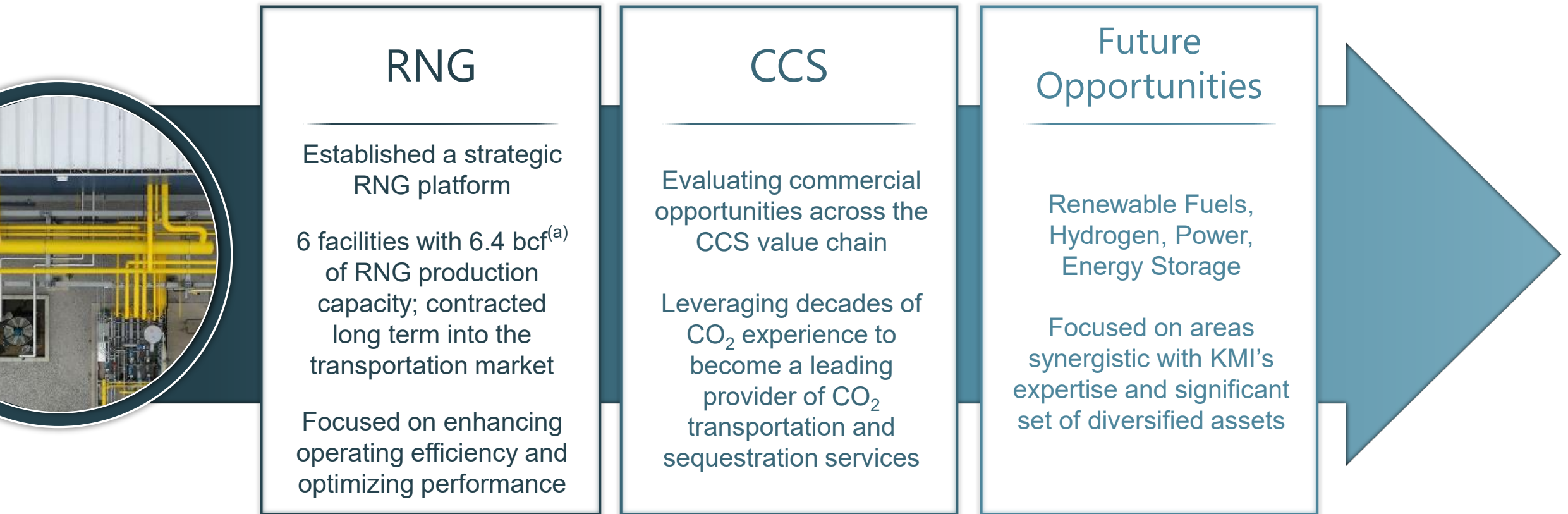
— CO₂ EOR & TRANSPORT FREE CASH FLOW — \$ Millions

■ FCF □ Capex^(a) ■ Acquisitions ◇ Adj. Segment EBDA

>\$2 billion FCF Generated Over 5 years



Pursuing Commercial Opportunities Emerging from the Lower Carbon Energy Evolution



Committed to Being a Good Steward



Reduce & Avoid
Methane Emissions

~10%

Reduction in
methane emissions
intensity since 2022



Leak
Detection

100%

of our natural gas
compressor stations
surveyed annually



Continuous
Improvement

BB → AAA

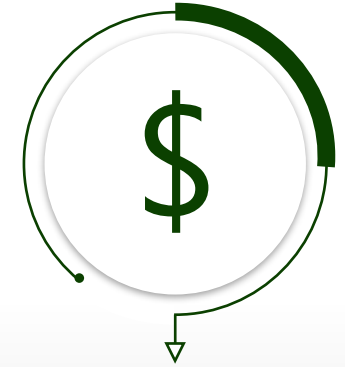
MSCI score
improvement
2018 – 2024



Employee
Development

283

Participants in
our leadership
training



Investing in Lower
Carbon Fuels

\$8.4bn

Primarily natural gas;
remaining investment
in RNG and CCS^(a)

Dedicated to Doing Business the Right Way, Every Day – Serving Our Investors,
Our Colleagues, Our Customers, and Our Neighbors to Improve Lives and Create A Better World

Sustainability Ratings Recognition

Highly rated by multiple agencies

MSCI **AAA**

Oil & Gas Refining,
Marketing, Transportation
& Storage Industry

Sustainalytics **Top 10%**

out of 84 Oil & Gas
Storage and Transportation Companies &
166 Refiners & Pipelines

Refinitiv **#5**

of 237 Oil & Gas
Related Equipment
and Services Companies

S&P Global CSA

**Sustainability Yearbook
Member**

FTSE **#2**

of Oil & Gas
Pipelines subsector

Included in several sustainability indices FTSE4Good, S&P 500 Scored and Screened, JULCD, MSCI Climate & ESG Indices



APPENDIX

Contract Strategy Insulates Cash Flows Through Commodity Cycles

Structure Long-Term Contracts That Minimize Price & Volume Volatility

		Take-or-Pay or Hedged Volumes & price are contractually fixed	Fee-Based Price is fixed, volumes are variable	Commodity- Price Based	Avg. remaining contract term as of 12/31/2024	Additional cash flow security
Natural Gas	Interstate / LNG	40%	3%		6.3 / 15.7 years	Tariffs are FERC-regulated
	TX Intrastate	12%	4%		7.3 years	
	G&P	1% ^(a)	4%	1%	3.9 years	Primarily acreage dedications for fee-based contracts
Products	Refined products	1%	9%	1%	generally not applicable	Pipeline tariffs are FERC-regulated
	Crude transport	1%			4.4 years ^(b)	~72% of 2025B Products Adj. Segment EBDA has an annual inflation-linked tariff escalator
	Crude G&P		1%			
Terminals	Liquids terminals	5%	2%		1.8 years	~73% of 2025B Terminals Adj. Segment EBDA has annual price escalators (inflation-linked or fixed-price escalators)
	Jones Act tankers	3%			4.0 years	
	Bulk terminals	1%	2%		3.0 years	Bulk terminals: primarily minimum volume guarantee or requirements
CO ₂	EOR Oil & Gas	4% ^(a)		1%		
	CO ₂ & Transport	1%	1%		5.8 years	Commodity-price based contracts are mostly minimum volume committed
	ETV			2%		
		69%	26%	5%		

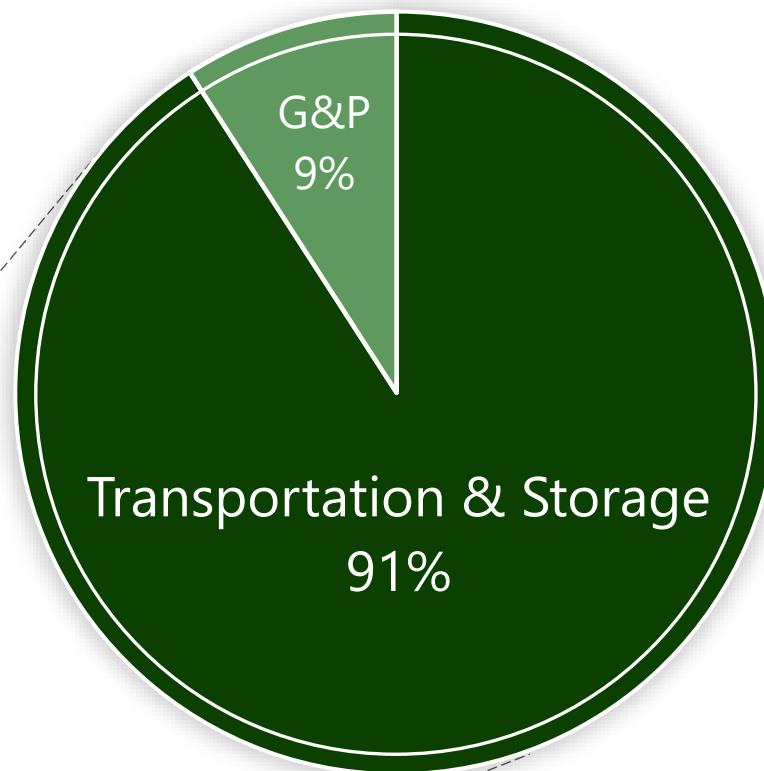
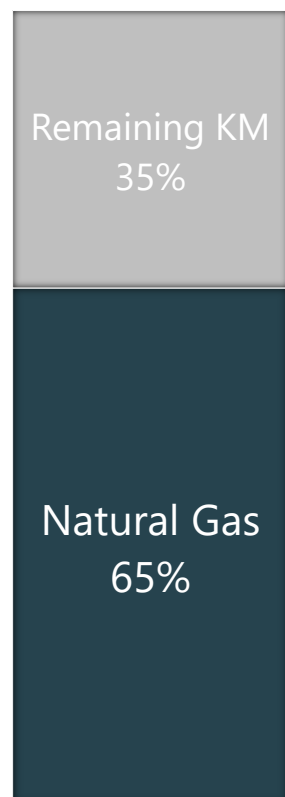
Note: Total Adjusted Segment EBDA is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations. TX Intrastate average remaining contract life includes term sale portfolio.

a) Hedged cash flows.

b) Includes condensate splitter. Excludes remaining contract life for Double H, which is to be converted from crude oil service to NGL service and will report under our Natural Gas business unit going forward.

High-Quality, Natural Gas Focused Cash Flows

CASH FLOW MIX^(a)



Natural Gas Transportation & Storage

- Accounts for 59% of 2025B KMI Adjusted Segment EBDA
- 88% take-or-pay cash flows^(a)
- Average remaining contract life:
 - ~7 years for transportation
 - ~4 years for storage

KMI's percent cash flow contribution from long-haul natural gas pipelines is greater than any other large U.S. midstream company^(b)

a) Based on 2025 budgeted Total Adjusted Segment EBDA, which is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations.

b) Includes U.S. based midstream companies with market capitalizations greater than \$20 billion.

Use of Non-GAAP Financial Measures

Our non-GAAP financial measures described below should not be considered alternatives to GAAP net income attributable to Kinder Morgan, Inc. or other GAAP measures and have important limitations as analytical tools. Our computations of these non-GAAP financial measures may differ from similarly titled measures used by others. You should not consider these non-GAAP financial measures in isolation or as substitutes for an analysis of our results as reported under GAAP. Management compensates for the limitations of our consolidated non-GAAP financial measures by reviewing our comparable GAAP measures identified in the descriptions of consolidated non-GAAP measures below, understanding the differences between the measures and taking this information into account in its analysis and its decision-making processes.

Adjusted Net Income Attributable to Kinder Morgan, Inc. is calculated by adjusting Net income attributable to Kinder Morgan, Inc. for Certain Items. Adjusted Net Income Attributable to Kinder Morgan, Inc. is used by us, investors and other external users of our financial statements as a supplemental measure that provides decision-useful information regarding our period-over-period performance and ability to generate earnings that are core to our ongoing operations. We believe the GAAP measure most directly comparable to Adjusted Net Income Attributable to Kinder Morgan, Inc. is Net income attributable to Kinder Morgan, Inc.

Adjusted Net Income Attributable to Common Stock is calculated by adjusting net income attributable to Kinder Morgan, Inc., the most comparable GAAP measure, for Certain Items, and further for net income allocated to participating securities and adjusted net income in excess of distributions for participating securities. For periods from 2016 to 2018, also reflects an adjustment for preferred stock dividends. We believe Adjusted Net Income Attributable to Common Stock allows for calculation of Adjusted EPS on the most comparable basis with earnings per share, the most comparable GAAP measure to Adjusted EPS. **Adjusted EPS** is calculated as Adjusted Net Income Attributable to Common Stock divided by our weighted average shares outstanding. Adjusted EPS applies the same two-class method used in arriving at basic earnings per share. Adjusted EPS is used by us, investors and other external users of our financial statements as a per-share supplemental measure that provides decision-useful information regarding our period-over-period performance and ability to generate earnings that are core to our ongoing operations.

Certain Items, as adjustments used to calculate our non-GAAP financial measures, are items that are required by GAAP to be reflected in Net income attributable to Kinder Morgan, Inc., but typically either (i) do not have a cash impact (for example, unsettled commodity hedges and asset impairments), or (ii) by their nature are separately identifiable from our normal business operations and in most cases are likely to occur only sporadically (for example, certain legal settlements, enactment of new tax legislation and casualty losses). We also include adjustments related to joint ventures (see “Amounts associated with Joint Ventures” below).

Adjusted Segment EBDA is calculated, for an individual segment, by adjusting segment earnings before DD&A, general and administrative expenses and corporate charges, interest expense, and income taxes (Segment EBDA) for Certain Items attributable to the segment. Adjusted Segment EBDA is used by management in its analysis of segment performance and management of our business. We believe Adjusted Segment EBDA is a useful performance metric because it provides management, investors and other external users of our financial statements additional insight into performance trends across our business segments, our segments’ relative contributions to our consolidated performance and the ability of our segments to generate earnings on an ongoing basis. Adjusted Segment EBDA is also used as a factor in determining compensation under our annual incentive compensation program for our business segment presidents and other business segment employees. We believe it is useful to investors because it is a measure that management uses to allocate resources to our segments and assess each segment’s performance. We believe the GAAP measure most directly comparable to Adjusted Segment EBDA is Segment EBDA. **Total Adjusted Segment EBDA** is calculated as the sum of all our segments’ respective Adjusted Segment EBDA or, to the extent that a segment has no reportable Certain Items, Segment EBDA.

Adjusted EBITDA is calculated by adjusting Net income attributable to Kinder Morgan, Inc. before interest expense, income taxes, DD&A, and amortization of basis differences related to our joint ventures (EBITDA) for Certain Items. For periods from 2017 to 2019, Adjusted EBITDA also reflects an adjustment for Kinder Morgan Canada Limited noncontrolling interest. We also include amounts from joint ventures for income taxes and DD&A (see “Amounts associated with Joint Ventures” below). Adjusted EBITDA (on a rolling 12-months basis) is used by management, investors and other external users, in conjunction with our Net Debt (as described further below), to evaluate our leverage. Management and external users also use Adjusted EBITDA as an important metric to compare the valuations of companies across our industry. Our ratio of Net Debt-to-Adjusted EBITDA is used as a supplemental performance target for purposes of our annual incentive compensation program. We believe the GAAP measure most directly comparable to Adjusted EBITDA is Net income attributable to Kinder Morgan, Inc.

Use of Non-GAAP Financial Measures (Continued)

Amounts Associated with Joint Ventures - Certain Items, DCF and Adjusted EBITDA reflect amounts from unconsolidated joint ventures (JVs) and consolidated JVs utilizing the same recognition and measurement methods used to record “Earnings from equity investments” and “Noncontrolling interests (NCI),” respectively. The calculations of DCF and Adjusted EBITDA related to our unconsolidated and consolidated JVs include the same items (DD&A amortization of basis differences and income tax expense, and for DCF only, also cash taxes and sustaining capital expenditures) with respect to the JVs as those included in the calculations of DCF and Adjusted EBITDA for our wholly-owned consolidated subsidiaries; further, we remove the portion of these adjustments attributable to non-controlling interests. Although these amounts related to our unconsolidated JVs are included in the calculations of DCF and Adjusted EBITDA, such inclusion should not be understood to imply that we have control over the operations and resulting revenues, expenses or cash flows of such unconsolidated JVs.

Net Debt is calculated by subtracting from debt (1) cash and cash equivalents, (2) debt fair value adjustments, and (3) the foreign exchange impact on Euro-denominated bonds for which we have entered into currency swaps. Net Debt, on its own and in conjunction with our Adjusted EBITDA (on a rolling 12-months basis) as part of a ratio of Net Debt-to-Adjusted EBITDA, is a non-GAAP financial measure that is used by management, investors, and other external users of our financial information to evaluate our leverage. For periods from 2016 to 2018, Net Debt also reflects subtraction of the preferred interest in the general partner of Kinder Morgan Energy Partners L.P. Our ratio of Net Debt-to-Adjusted EBITDA is also used as a supplemental performance target for purposes of our annual incentive compensation program. We believe the GAAP measure most comparable measure to Net Debt is total debt.

DCF, or Distributable Cash Flow, is calculated by adjusting Net income attributable to Kinder Morgan, Inc. for Certain Items, and further for DD&A and amortization of excess cost of equity investments, income tax expense, cash taxes, sustaining capital expenditures and other items. We also adjust amounts from joint ventures for income taxes, DD&A, cash taxes and sustaining capital expenditures (see “Amounts from Joint Ventures” above). DCF is used by us to evaluate our performance and to measure and estimate the ability of our assets to generate economic earnings after paying interest expense, paying cash taxes and expending sustaining capital. DCF provides additional insight into the specific costs associated with our assets in the current period and facilitates period-to-period comparisons of our performance from ongoing business activities. DCF per share serves as the primary financial performance target for purposes of annual bonuses under our annual incentive compensation program and for performance-based vesting of equity compensation grants under our long-term incentive compensation program. DCF should not be used as an alternative to net cash provided by operating activities computed under GAAP. We believe the GAAP measure most directly comparable to DCF is Net income attributable to Kinder Morgan, Inc. **DCF per share** is DCF divided by average outstanding shares, including restricted stock awards that participate in dividends.

Project EBITDA, which we use to calculate EBITDA build multiples, is calculated for an individual capital project as earnings before interest expense, taxes, DD&A and general and administrative expenses attributable to such project, or for JV projects, consistent with the methods described above under “Amounts associated with Joint Ventures,” and in conjunction with capital expenditures for the project. Management, investors and others use Project EBITDA to evaluate our return on investment for capital projects before expenses that are generally not controllable by operating managers in our business segments. We believe the GAAP measure most directly comparable to Project EBITDA is the portion of net income attributable to a capital project. We do not provide the portion of budgeted net income attributable to individual capital projects (the GAAP financial measure most directly comparable to Project EBITDA) due to the impracticality of predicting, on a project-by-project basis through the second full year of operations, certain amounts required by GAAP, such as projected commodity prices, unrealized gains and losses on derivatives marked to market, and potential estimates for certain contingent liabilities associated with the project completion.

Acquisition EBITDA Multiples - With respect to projected EBITDA multiples associated with acquired assets or businesses, we do not provide the portion of budgeted net income attributable to individual acquisitions (the GAAP financial measure most directly comparable to projected EBITDA for acquired assets or businesses) due to the impracticality of predicting, certain amounts required by GAAP, such as projected commodity prices, unrealized gains and losses on derivatives marked to market, and potential estimates for certain contingent liabilities associated with the acquisition.

FCF, or Free Cash Flow, is calculated by reducing cash flow from operations for capital expenditures (sustaining and expansion), and FCF after dividends is calculated by further reducing FCF for dividends paid during the period. FCF is used by management, investors and other external users as an additional leverage metric, and FCF after dividends provides additional insight into cash flow generation. We believe the GAAP measure most directly comparable to FCF is cash flow from operations.

CO₂ EOR & Transport, Terminals and Product Pipelines Free Cash Flow is calculated by reducing Segment EBDA from our CO₂ EOR & Transport assets, Terminals, and Products Pipeline segment by Certain Items, capital expenditures (sustaining and expansion) and acquisitions attributable to the EOR & Transport assets, Terminals, and Products Pipeline segment. Management uses CO₂ EOR & Transport, Terminals, and Product Pipelines Free Cash Flow as an additional performance measure for our CO₂ EOR & Transport assets, Terminals, and Products Pipelines segment. We do not provide budgeted CO₂ EOR & Transport, Terminals, and Products Pipeline Segment EBDA (the GAAP financial measure most directly comparable to 2025 budgeted CO₂ EOR & Transport, Terminals, and Product Pipelines FCF) due to the inherent difficulty and impracticability of predicting certain amounts required by GAAP, such as potential changes in estimates for certain contingent liabilities and unrealized gains and losses.

Net Income, Adjusted EPS, & Adjusted EBITDA

In Billion

	2025 Forecast	2026 Budget
Net income attributable to KMI	\$ 2.9	\$ 3.1
Total Certain Items ^(a)	-	-
DD&A	2.4	2.5
Income tax expense ^(b)	0.8	0.9
Interest, net ^(b)	1.8	1.8
Amounts associated with joint ventures		
Unconsolidated JV DD&A ^(c)	0.4	0.4
Remove consolidated JV partners' DD&A	(0.1)	(0.1)
Unconsolidated JV income tax expense ^(d)	0.1	0.1
Adjusted EBITDA	\$ 8.3	\$ 8.7
Net income attributable to KMI	\$ 2.9	\$ 3.1
Total Certain Items ^(a)	-	-
Net income Allocated to participating securities and other ^{(a)(e)}	-	-
Adjusted Net income attributable to Common Stock^(f)	\$ 2.9	\$ 3.1

a) Aggregate adjustments are currently estimated to be less than \$100 million.

b) Amounts are adjusted for Certain Items.

c) Includes amortization of basis differences related to our JVs.

d) Includes the tax provision on Certain Items recognized by the investees that are taxable entities associated with our Citrus, NGPL and Products (SE) Pipe Line equity investments.

e) Participating securities consist of unvested stock awards issued to employees and non-employee directors. These awards receive dividend equivalents but do not share in net losses or distributions in excess of earnings. Other includes Adjusted net income in excess of distributions for participating securities.

f) Adjusted Net Income Attributable to Common Stock is used to calculate Adjusted EPS.

Net Income & Distributable Cash Flow (DCF)

In Billion, Except Per Share

	2025 Forecast	2026 Budget
Net income attributable to KMI	\$ 2.9	\$ 3.1
Total Certain Items ^(a)	-	-
DD&A	2.4	2.5
Income tax expense ^(b)	0.8	0.9
Cash taxes	-	-
Sustaining capital expenditures	(0.9)	(0.9)
Amounts associated with joint ventures		
Unconsolidated JV DD&A ^(c)	0.4	0.4
Remove consolidated JV partners' DD&A	(0.1)	(0.1)
Unconsolidated JV income tax expense ^(d)	0.1	0.1
Unconsolidated JV cash taxes	(0.1)	(0.1)
Unconsolidated JV sustaining capital expenditures	(0.2)	(0.2)
Remove consolidated JV partners' sustaining capital expenditures ^(a)	-	-
Other items ^{(a)(e)}	-	-
DCF	\$ 5.3	\$ 5.7
Weighted average shares outstanding for dividends ^(f)	2.236	2.237
DCF per share	\$ 2.38	\$ 2.55

a) Aggregate adjustments are currently estimated to be less than \$100 million.

b) Amounts are adjusted for Certain Items.

c) Includes amortization of basis differences related to our JVs.

d) Includes the tax provision on Certain Items recognized by the investees that are taxable entities associated with our Citrus, NGPL and Products (SE) Pipe Line equity investments.

e) Includes pension contributions, non-cash pension expense and non-cash compensation associated with our restricted stock program.

f) Includes 13 million and 11 million average unvested restricted shares that participate in dividends in 2025 and 2026, respectively.

Net Income, Adjusted Net Income Attributable to KMI, and DCF

\$ in Millions

	2025 Budget	2024 Actual	Change		Q3 2025 Actual
			\$	%	
Net income attributable to KMI	\$ 2,829	\$ 2,613	\$ 216	8%	\$ 628
Certain Items					
Change in fair value of derivative contracts	-	72	(72)	(100%)	24
Loss on impairment	-	(69)	69	100%	-
Income tax Certain Items	-	(52)	52	100%	(4)
Other	2	7	(5)	(71%)	-
Total Certain Items	2	(42)	44	105%	20
Adjusted Net Income Attributable to KMI	\$ 2,831	\$ 2,571	\$ 260	10%	\$ 648
Net income attributable to KMI	\$ 2,829	\$ 2,613	\$ 216	8%	\$ 628
Total Certain Items	2	(42)	44	105%	20
DD&A	2,411	2,354	57	2%	609
Income tax expense ^(a)	817	739	78	11%	189
Cash taxes	(77)	(33)	(44)	(133%)	(5)
Sustaining capital expenditures	(938)	(986)	48	5%	(257)
Amounts associated with joint ventures					
Unconsolidated JV DD&A ^(b)	408	409	(1)	(0%)	96
Remove consolidated JV partners' DD&A	(64)	(62)	(2)	(3%)	(16)
Unconsolidated JV income tax expense ^{(c)(d)}	85	78	7	9%	20
Unconsolidated JV cash taxes ^(c)	(82)	(48)	(34)	(71%)	(8)
Unconsolidated JV sustaining capital expenditures	(184)	(189)	5	3%	(43)
Remove consolidated JV partners' sustaining capital expenditures	10	10	-	-	2
Other items ^(e)	24	38	(14)	(37%)	8
DCF	\$ 5,241	\$ 4,881	\$ 360	7%	\$ 1,243
Weighted average shares outstanding for dividends ^(f)	2,237	2,233	4	0%	2,237
DCF per share ^(g)	\$ 2.34	\$ 2.19	\$ 0.15	7%	\$ 0.56

Note: Adjusted Earnings and Distributable Cash Flow (DCF), in aggregate and per share, are non-GAAP financial measures. See Non-GAAP Financial Measures and Reconciliations.

- a) To avoid duplication, amounts are adjusted to exclude amounts which are already included within "Certain Items" above.
- b) Includes amortization of basis differences related to our JVs.
- c) Associated with our Citrus, NGPL and Products (SE) Pipe Line equity investments.
- d) Includes the tax provision on Certain Items recognized by the investees that are taxable entities. The impact of KMI's income tax provision on Certain Items affecting earnings from equity investments is included within "Certain Items" above.
- e) Includes pension contributions, non-cash pension expense and non-cash compensation associated with our restricted stock program.
- f) Includes 15 million, 15 million, and 13 million average unvested restricted shares that participate in dividends in 2025 Budget, 2024, and Q3 2025 actuals, respectively.
- g) 2025 Budget DCF per share of \$2.34 consists of the following quarterly amounts: Q1 \$0.66, Q2 \$0.49, Q3 \$0.54, Q4 \$0.65.

2014 and 2025B Reconciliation of Segment EBDA to Adjusted Segment EBDA

\$ in Millions

Segment EBDA ^(a)	2025 Budget	2014 Actual
Natural Gas Pipelines Segment EBDA	\$ 5,636	\$ 4,288
Certain Items ^(b)		
Contract early termination revenue	-	(198)
Change in fair value of derivative contracts	-	2
Loss on impairments, divestitures and other write-downs, net	-	(1)
Other	-	4
Certain Items	-	(193)
Natural Gas Pipelines Adjusted Segment EBDA	5,636	4,095
Products Pipelines Segment EBDA	1,179	787
Certain Items ^(b)		
Loss on impairments, divestitures and other write-downs, net	-	3
Other	-	4
Certain Items	-	7
Products Pipelines Adjusted Segment EBDA	1,179	794
Terminals Segment EBDA	1,103	973
Certain Items ^(b)		
Loss on impairments, divestitures and other write-downs, net	-	29
Other	-	6
Certain Items	-	35
Terminals Adjusted Segment EBDA	1,103	1,008

Segment EBDA ^(a)	2025 Budget	2014 Actual
CO ₂ Segment EBDA	755	1,248
Certain Items ^(b)		
Change in fair value of derivative contracts	-	(25)
Loss on impairments, divestitures and other write-downs, net	-	243
Certain Items	-	218
CO ₂ Adjusted Segment EBDA ^(c)	755	1,466
Canada Adjusted Segment EBDA	-	200
Total Adjusted Segment EBDA ^(d)	\$ 8,673	\$ 7,563

a) Includes revenues, earnings from equity investments, operating expenses, other (income) expense, net, and other, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes. The composition of Segment EBDA is not addressed nor prescribed by generally accepted accounting principles. 2014 amounts are adjusted to reflect categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change.

b) See "Non-GAAP Financial Measures—Certain Items."

c) 2025 includes \$140 million of EBDA associated with our ETV business. 2014 actuals consist of only our CO₂ EOR and Transport business.

d) Calculated as the sum of all our segments' respective Adjusted Segment EBDA or, to the extent that a segment has no reportable Certain Items, Segment EBDA.

2024 Reconciliation of Recasted Adjusted Segment EBDA

\$ in Millions

Segment EBDA ^(a)	2024 Actual	Adjustment ^(b)	2024 Recasted
Natural Gas Pipelines Segment EBDA	\$ 5,427	\$ (34)	\$ 5,393
Certain Items ^(c)			-
Change in fair value of derivative contracts	75	-	75
Loss on impairments, divestitures and other write-downs, net	(29)	-	(29)
Certain Items	46	-	46
Natural Gas Pipelines Adjusted Segment EBDA	5,473	(34)	5,439
Products Pipelines Segment EBDA	1,173	(9)	1,164
Certain Items	-	-	-
Products Pipelines Adjusted Segment EBDA	1,173	(9)	1,164
Terminals Segment EBDA	1,099	(0)	1,099
Certain Items	-	-	-
Terminals Adjusted Segment EBDA	1,099	(0)	1,099
CO ₂ Segment EBDA	692	(7)	685
Certain Items ^(c)			-
Change in fair value of derivative contracts	2	-	2
Loss on impairments, divestitures and other write-downs, net	(40)	-	(40)
Certain Items	(38)	-	(38)
CO ₂ Adjusted Segment EBDA ^(d)	654	(7)	647
Total Adjusted Segment EBDA ^(e)	\$ 8,399	\$ (50)	\$ 8,349

a) Includes revenues, earnings from equity investments, operating expenses, other (income) expense, net, and other, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes. The composition of Segment EBDA is not addressed nor prescribed by generally accepted accounting principles.

b) Represents categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change.

c) See "Non-GAAP Financial Measures—Certain Items."

d) Includes \$45 million of EBDA associated with our ETV business.

e) Calculated as the sum of all our segments' respective Adjusted Segment EBDA or, to the extent that a segment has no reportable Certain Items, Segment EBDA.

Reconciliation of Adjusted Net Income Attributable to Common Stock and Adjusted EPS

\$ in Millions

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025B
Net income attributable to KMI	\$ 708	\$ 183	\$ 1,609	\$ 2,190	\$ 119	\$ 1,784	\$ 2,548	\$ 2,391	\$ 2,613	\$ 2,829
NCI associated with Certain Items	(8)	-	-	-	-	-	-	-	-	-
Certain Items										
Fair value amortization	(143)	(53)	(34)	(29)	(21)	(19)	(15)	-	-	-
Legal, environmental and other reserves	(16)	(37)	12	46	26	160	51	-	-	-
Change in fair value of derivative contracts	75	40	80	(24)	(5)	19	57	(126)	72	-
Loss on impairment	848	170	317	(280)	1,927	1,535	-	67	(69)	-
Project write-offs	171	-	-	-	-	-	-	-	-	-
Impact of 2017 Tax Cuts and Jobs Act	-	219	(36)	-	-	-	-	-	-	-
Income tax Certain Items	18	1,085	(58)	299	(107)	(491)	(37)	33	(52)	-
Noncontrolling interests	-	-	240	(4)	-	-	-	-	-	-
Other	(20)	21	(20)	(37)	72	16	32	45	7	2
Total Certain Items	933	1,445	501	(29)	1,892	1,220	88	19	(42)	2
Preferred stock dividends	(156)	(156)	(128)	-	-	-	-	-	-	-
Net income allocated to participating securities ^(a)	(4)	(5)	(8)	(12)	(13)	(14)	(13)	(14)	(15)	(19)
Other ^(b)	(1)	(1)	(2)	-	-	(3)	(1)	-	1	-
Adjusted Net Income Attributable to Common Stock	\$ 1,472	\$ 1,466	\$ 1,972	\$ 2,149	\$ 1,998	\$ 2,987	\$ 2,622	\$ 2,396	\$ 2,557	\$ 2,812
Weighted average shares outstanding	2,230	2,230	2,216	2,264	2,263	2,266	2,258	2,234	2,220	2,222
Adjusted EPS	\$ 0.66	\$ 0.66	\$ 0.89	\$ 0.95	\$ 0.88	\$ 1.32	\$ 1.16	\$ 1.07	\$ 1.15	\$ 1.27

a) Net income allocated to participating securities is based on the amount of dividends paid in the current period plus an allocation of the undistributed earnings or excess distributions over earnings, as applicable.

b) Adjusted net income in excess of distributions for participating securities.

Reconciliations of KMI FCF and CO₂ EOR & Transport FCF

\$ in Millions

Reconciliation of KMI FCF	2020	2021	2022	2023	2024	2025B
CFFO (GAAP)	\$ 4,550	\$ 5,708	\$ 4,967	\$ 6,491	\$ 5,635	\$ 5,899
Capital expenditures (GAAP) ^(a)	(1,707)	(1,281)	(1,621)	(2,317)	(2,629)	(3,141)
FCF	2,843	4,427	3,346	4,174	3,006	2,758
Dividends paid (GAAP)	(2,362)	(2,443)	(2,504)	(2,529)	(2,557)	(2,606)
FCF after dividends	\$ 481	\$ 1,984	\$ 842	\$ 1,645	\$ 449	\$ 152

Reconciliation of CO₂ EOR & Transport FCF

EBDA for CO ₂ EOR & Transport ^(b)	\$ (294)	\$ 750	\$ 798	\$ 658	\$ 640	\$ 615
Certain items:						
Change in fair value of derivative contracts	(6)	4	(11)	4	2	-
Loss (gain) on impairments, divestitures and other write-downs, net	950	(10)	-	-	(40)	-
Segment Certain Items	944	(6)	(11)	4	(38)	-
Adjusted EBDA for CO₂ EOR & Transport	650	744	787	662	602	615
Capital expenditures (GAAP) ^(a)	(186)	(185)	(275)	(255)	(280)	(303)
Acquisitions	-	-	-	(13)	(64)	-
CO₂ EOR & Transport FCF	\$ 464	\$ 559	\$ 512	\$ 394	\$ 258	\$ 312

a) Includes sustaining and expansion capital expenditures.

b) Includes revenues, earnings from equity investments, operating expenses, other (income) expense, net, and other, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes. The composition of Segment EBDA is not addressed nor prescribed by generally accepted accounting principles.

Reconciliations of Terminals FCF and Products Pipelines FCF

\$ in Millions

Reconciliation of Terminals FCF	2020	2021	2022	2023	2024	2025B
EBDA for Terminals ^(b)	\$ 1,045	\$ 908	\$ 975	\$ 1,039	\$ 1,099	\$ 1,103
Certain items:						
Loss (gain) on impairments, divestitures and other write-downs, net	(55)	34	-	-	-	-
Other	-	8	-	-	-	-
Segment Certain Items	(55)	42	-	-	-	-
Adjusted EBDA for Terminals	990	950	975	1,039	1,099	1,103
Capital expenditures (GAAP) ^(a)	(433)	(332)	(552)	(406)	(385)	(367)
Acquisitions	(8)	-	-	-	-	-
Terminals FCF	\$ 549	\$ 618	\$ 423	\$ 633	\$ 714	\$ 736

Reconciliation of Products Pipelines FCF	2020	2021	2022	2023	2024	2025B
EBDA for Products Pipelines ^(b)	\$ 967	\$ 1,041	\$ 1,072	\$ 1,033	\$ 1,164	\$ 1,179
Certain items:						
Legal, environmental and other reserves	46	53	-	-	-	-
Change in fair value of derivative contracts	-	-	-	(1)	-	-
Loss on impairments and divestitures, net	21	-	-	67	-	-
Other	(17)	-	-	-	-	-
Segment Certain Items	50	53	-	66	-	-
Adjusted EBDA for Products Pipelines	1,017	1,094	1,072	1,099	1,164	1,179
Capital expenditures (GAAP) ^(a)	(122)	(122)	-	(221)	(210)	(222)
Acquisitions	(8)	-	-	-	-	-
Products Pipelines FCF	\$ 887	\$ 972	\$ 1,072	\$ 878	\$ 954	\$ 957

a) Includes sustaining and expansion capital expenditures.

b) Includes revenues, earnings from equity investments, operating expenses, other (income) expense, net, and other, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes. The composition of Segment EBDA is not addressed nor prescribed by generally accepted accounting principles.

Reconciliation of Adjusted EBITDA, Normalized for Divestitures

\$ in Millions

Reconciliation of Adjusted EBITDA, Normalized for Divestitures	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025B
Net income attributable to KMI	\$ 708	\$ 183	\$ 1,609	\$ 2,190	\$ 119	\$ 1,784	\$ 2,548	\$ 2,391	\$ 2,613	\$ 2,829
NCI associated with Certain Items	(8)	-	-	-	-	-	-	-	-	-
KML noncontrolling interests ^(a)	-	28	58	33	-	-	-	-	-	-
Certain Items										
Fair value amortization	(143)	(53)	(34)	(29)	(21)	(19)	(15)	-	-	-
Legal, environmental and other reserves	(16)	(37)	12	46	26	160	51	-	-	-
Change in fair value of derivative contracts	75	40	80	(24)	(5)	19	57	(126)	72	-
Loss on impairment	848	170	317	(280)	1,927	1,535	-	67	(69)	-
Project write-offs	171	-	-	-	-	-	-	-	-	-
Impact of 2017 Tax Cuts and Jobs Act	-	219	(36)	-	-	-	-	-	-	-
Income tax Certain Items	18	1,085	(58)	299	(107)	(491)	(37)	33	(52)	-
Noncontrolling interests	-	-	240	(4)	-	-	-	-	-	-
Other	(20)	21	(20)	(37)	72	16	32	45	7	2
Total Certain Items	933	1,445	501	(29)	1,892	1,220	88	19	(42)	2
DD&A	2,209	2,261	2,297	2,411	2,164	2,135	2,186	2,250	2,354	2,411
Income tax expense ^(a)	899	853	645	627	588	860	747	682	739	817
Interest, net ^(a)	1,999	1,871	1,891	1,816	1,610	1,518	1,524	1,804	1,849	1,796
Amounts associated with joint ventures										
Unconsolidated JV DD&A ^(b)	421	459	507	494	547	390	398	389	409	408
Remove consolidated JV partners' DD&A	(13)	(16)	(22)	(19)	(40)	(44)	(50)	(63)	(62)	(64)
Unconsolidated JV income tax expense ^(a)	94	114	82	95	82	83	75	89	78	85
Adjusted EBITDA	\$ 7,242	\$ 7,198	\$ 7,568	\$ 7,618	\$ 6,962	\$ 7,946	\$ 7,516	\$ 7,561	\$ 7,938	\$ 8,284
Divested adjusted EBITDA ^(a)	(789)	(672)	(660)	(503)	(142)	(118)	(139)	(54)	(17)	-
As normalized for divestitures	\$ 6,453	\$ 6,526	\$ 6,908	\$ 7,115	\$ 6,820	\$ 7,828	\$ 7,377	\$ 7,507	\$ 7,921	\$ 8,284

a) To avoid duplication, amounts are adjusted to exclude amounts which are already included within "Certain Items" above.

b) Includes amortization of basis differences related to our JVs.

Reconciliation of Net Debt

\$ in Millions

Reconciliation of Net Debt	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025B
Current portion of debt	\$ 2,696	\$ 2,828	\$ 3,388	\$ 2,377	\$ 2,558	\$ 2,646	\$ 3,385	\$ 4,049	\$ 2,009	\$ 1,209
Total long-term debt	37,354	35,015	33,936	31,915	32,131	30,674	28,403	28,067	29,881	30,207
Debt fair value adjustments	(1,149)	(927)	(731)	(1,032)	(1,293)	(902)	(115)	(187)	(102)	
Preferred interest in general partner of KMP	(100)	(100)	(100)	-	-	-	-	-	-	-
Foreign exchange impact on hedges for Euro Debt outstanding	43	(143)	(76)	(44)	(170)	(64)	8	(9)	25	
Less: cash & cash equivalents	(684)	(264)	(3,280)	(185)	(1,184)	(1,140)	(745)	(83)	(88)	(8)
Net Debt	\$ 38,160	\$ 36,409	\$ 33,137	\$ 33,031	\$ 32,042	\$ 31,214	\$ 30,936	\$ 31,837	\$ 31,725	\$ 31,408
Adjusted EBITDA	\$ 7,242	\$ 7,198	\$ 7,568	\$ 7,618	\$ 6,962	\$ 7,946	\$ 7,516	\$ 7,561	\$ 7,938	\$ 8,284
Net Debt to Adjusted EBITDA	5.3X	5.1X	4.4X	4.3X	4.6X	3.9X	4.1X	4.2X	4.0X	3.8X