KINDER MORGAN

INVESTOR PRESENTATION

1Q 2023

TransColorado Pipeline compressor station, Mancos, Colorado

Disclosure

Forward-looking statements / non-GAAP financial measures / industry & market data

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GAAP – Unless otherwise stated, all historical and estimated future financial and other information included in this presentation have 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, as well as reconciliations of historical non-GAAP financial measures to their most directly 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 and 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.

Leader in North American Energy Infrastructure

Energy infrastructure, especially natural gas pipelines & storage, has a decades-long time horizon moving and storing the energy of today and tomorrow

Largest natural gas transmission network

- ~70,000 miles of natural gas pipelines move ~40% of U.S. natural gas production
- Have interest in 700 bcf of working storage capacity, ~15% of U.S. natural gas storage

Largest independent transporter of refined products

- Transport ~1.7 mmbbld[(a)] of refined products to West and East Coast demand markets
- ~10,000 miles of refined products and crude pipelines

Largest independent terminal operator

- 140 terminals & 16 Jones Act vessels
- Significant provider of refined products storage along the Houston Ship Channel, near the world's most complex refining center

Largest CO_2 transport capacity of ~1.5 bcfd

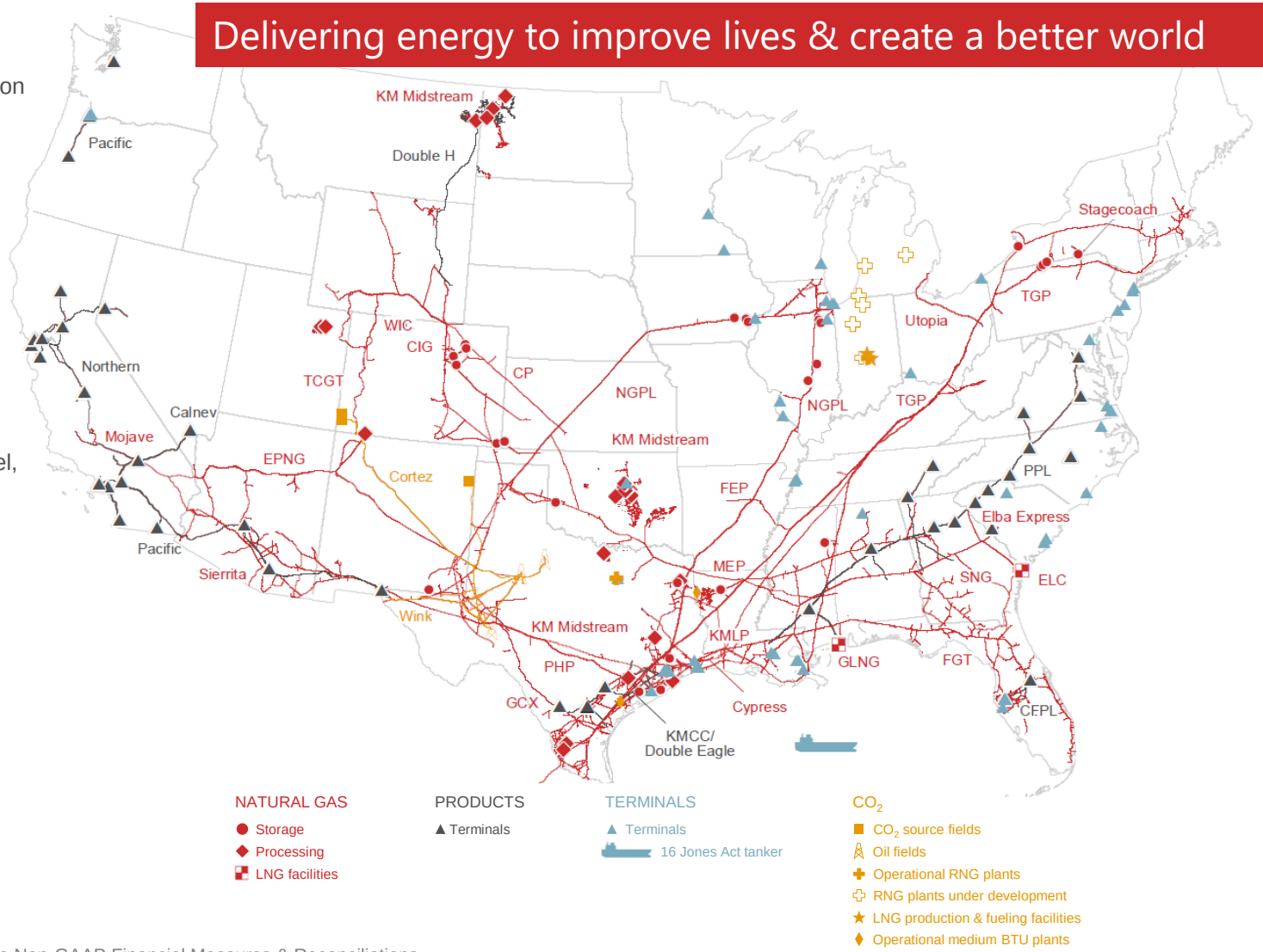
- ~1,500 miles of CO_2 pipelines
- Produce CO_2 and transport to the Permian where it is used for enhanced oil recovery

Growing Energy Transition Portfolio

- Up to 7.0 bcf[(a)] of RNG production capacity by early 2024

Business Mix

Delivering energy to improve lives & create a better world



Note: Volumes per 2023 budget. Business mix based on 2023 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
a) Annual capacity at KM share.

Strategy

Maximize the value of our assets on behalf of shareholders

Stable, fee-based assets

Core energy infrastructure

Safe & efficient operator

Multi-year contracts

~93% take-or-pay, hedged, & fee-based cash flows[a]

Invest in a low carbon future

Established Energy Transition Ventures Group in 2021

$3.3 billion backlog with 82% allocated to lower carbon investments

Investing in natural gas, RNG, liquid biofuels, and CCS infrastructure at attractive returns

Financial flexibility

4.0x 2023B expected YE Net Debt / Adjusted EBITDA

Long-term target remains around 4.5x

Low cost of capital

Mid-BBB credit ratings

Ample liquidity

Disciplined capital allocation

Conservative assumptions

High return thresholds

Self-funding capex & dividends for last 7 years

Reduced net debt by >$11 billion since 1Q 2015

Enhance shareholder value

Maintain strong balance sheet

Attractive investments

2023B dividend growth; +2% YoY

Share repurchases; $368mm in 2022

Natural gas storage wellhead, Houston, Texas

Note: Adjusted Segment EBDA and Net Debt/Adjusted EBITDA are non-GAAP measures. See Non-GAAP Financial Measures & Reconciliations.

a) Based on 2023 budgeted Adjusted Segment EBDA.

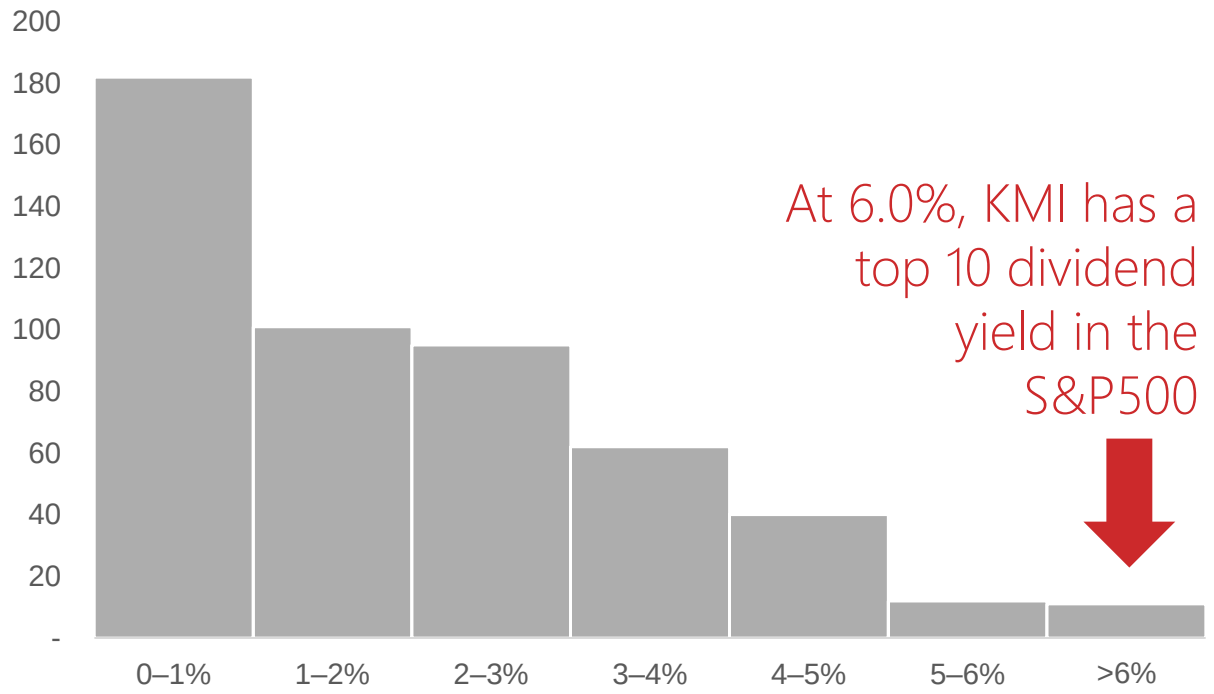
Core Holding in Any Portfolio

Generating significant cash flow & returning value to shareholders

>$70 billion enterprise value	Largest energy infrastructure company in the S&P500
~13% owned by management & board	Highly-aligned management with significant equity interests
$7.7 billion 2023 budget Adj. EBITDA	~$200mm increase year-over-year
~6% current dividend yield	Budgeted 2% dividend increase in 2023. Top 10 dividend in the S&P500
$3 billion share buyback program	~$2.1 billion of repurchase program remaining. $368mm of share repurchases in 2022

~36% of market cap value returned to shareholders since 2016

S&P500 CURRENT DIVIDEND YIELDS[a] y-axis represents # of S&P500 tickers within the dividend yield range specified on the x-axis



At 6.0%, KMI has a top 10 dividend yield in the S&P500

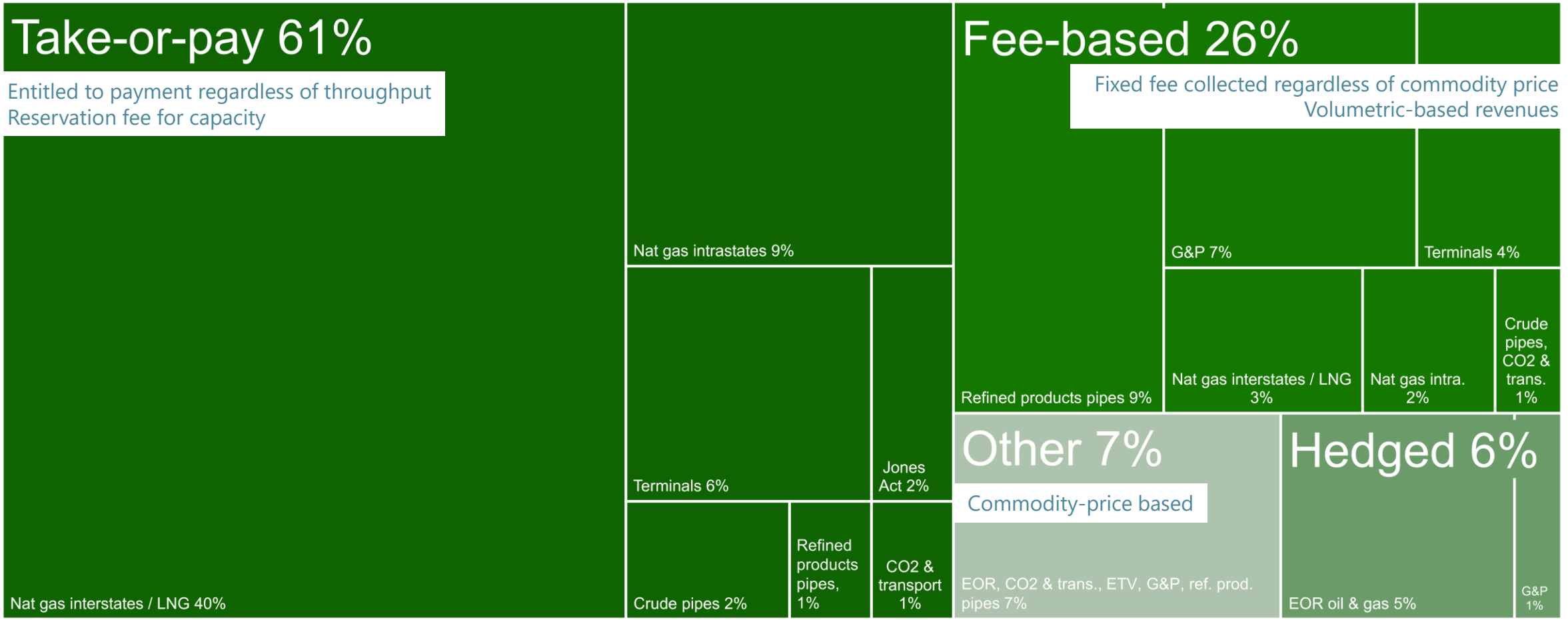
Note: Adjusted EBITDA is a non-GAAP measure. See Non-GAAP Financial Measures & Reconciliations.

a) Data based on current dividend and market capitalizations from Bloomberg for companies included in the S&P500 as of 1/18/2023.

Highly-Contracted Cash Flows

Stable cash flows with ~67% take-or-pay or hedged earnings

CONTRACT MIX OF 2023B ADJUSTED SEGMENT EBDA



Disciplined approach to managing price volatility
Substantially hedged near-term price exposure

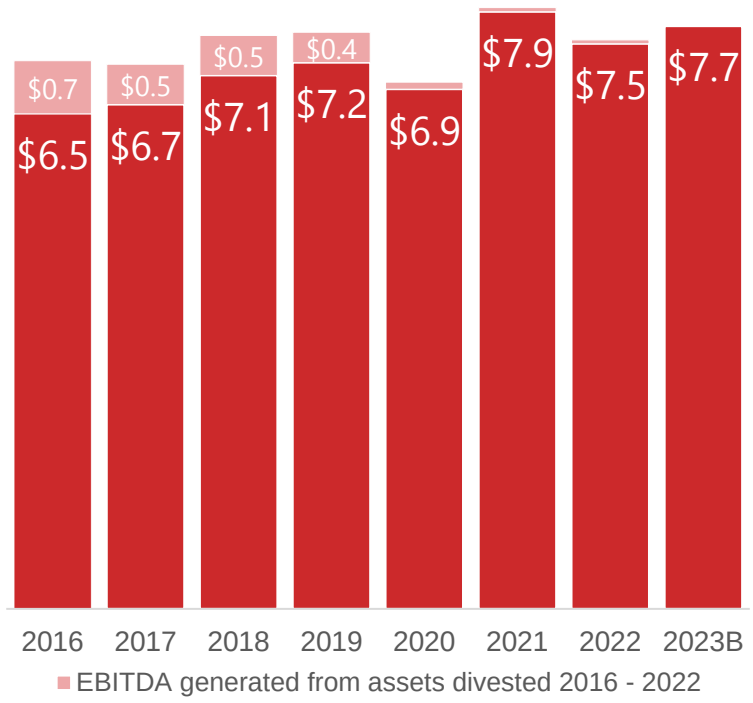
Note: Adjusted Segment EBDA is a non-GAAP measure. See Non-GAAP Financial Measures & Reconciliations.

Proven History of Cash Flow Generation and Shareholder Returns

$ billions

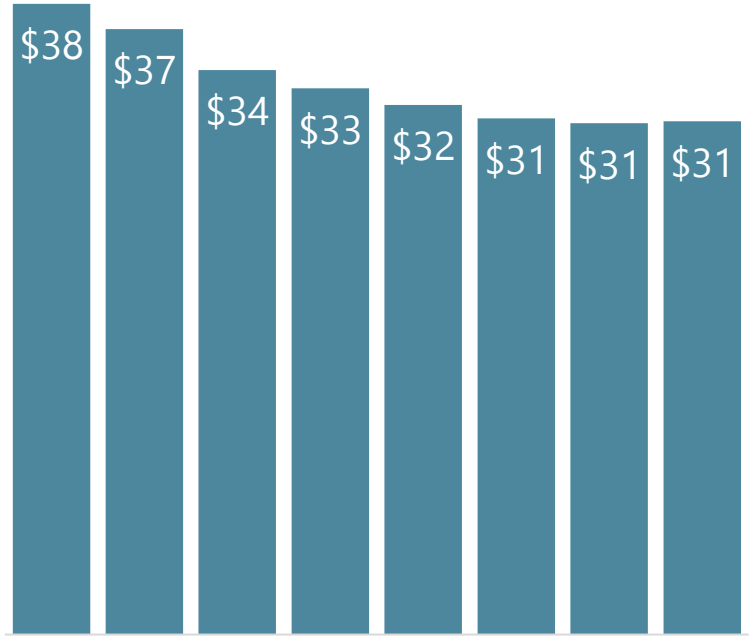
ADJUSTED EBITDA

+18%



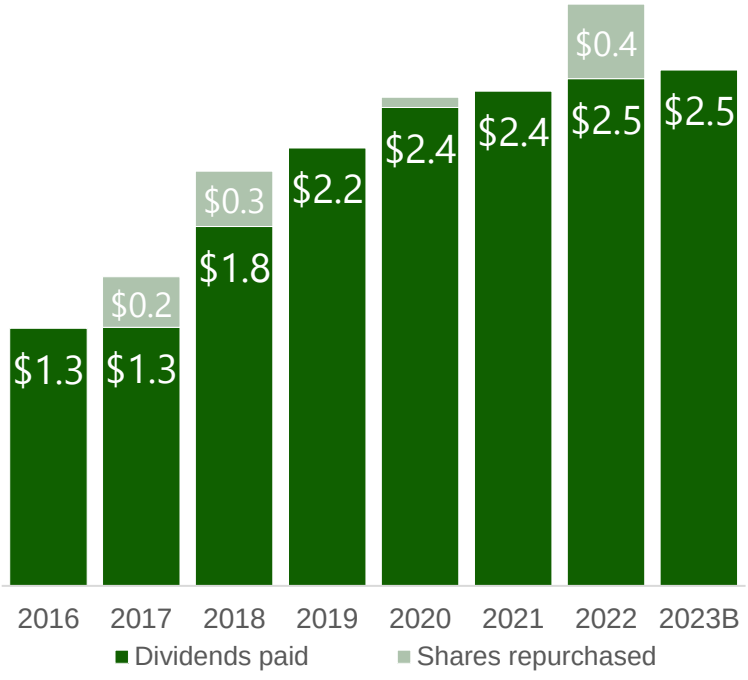
NET DEBT

-19%



DIVIDENDS PAID & SHARES REPURCHASED[a]

$17.3 billion returned to shareholders



Note: Adjusted EBITDA and Net Debt are non-GAAP measures. See Non-GAAP Financial Measures & Reconciliations.

a) No share repurchases assumed in 2023 budget. 2016, 2017, and 2018 include dividends paid to preferred shareholders.

2023 Guidance

Performance driven by strong market fundamentals and robust demand growth for our existing & expanded services

Key metrics	2023 Budget	Variance to 2022
Net income	$2.5 billion	-1%
Adjusted Segment EBDA	$8.2 billion	+4%
Adjusted EBITDA	$7.7 billion	+2%
Distributable Cash Flow (DCF)	$4.8 billion	-3%
Discretionary capital[(a)]	$2.1 billion	+$0.4 billion
Dividend / share	$1.13	+2%
Year-end Net Debt / Adj. EBITDA[(b)]	4.0x	

~$770 million

capacity available for attractive investments, including share repurchases, for each 0.1x turn below ~4.5x leverage target

Note: Adjusted Segment EBDA, Adjusted EBITDA, Distributable Cash Flow (DCF), and Net Debt/Adjusted EBITDA are non-GAAP measures. See Non-GAAP Financial Measures & Reconciliations.

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

b) No share repurchases assumed in 2023 budget.

$3.3bn Committed Growth Capital Project Backlog as of 12/31/2022

Expect 62% of backlog capital in service in 2023, 22% in 2024, and 16% beyond

$ million	TOTAL	LOWER CARBON	
Natural Gas	$ 2,121	$ 2,121	53% for end-use, 20% supply-push, 25% G&P, 2% CCS
Products	180	73	Renewable diesel projects
Terminals	281	200	Renewable feedstocks & VRU emission reduction projects
Energy Transition Ventures	331	331	98% RNG facilities; 2% CCS project
Subtotal	$ 2,912	$ 2,724	
EBITDA build multiple	~3.4x	~3.4x	
CO_2	$421		EOR projects
Total	$ 3,333		

Lower carbon investments ~82% of backlog

Expect annual growth capital spend of ~$1-2 billion going forward, compared to ~$2-3 billion historically

Note: The EBITDA build multiple reflects KM share of estimated capital divided by estimated Project EBITDA (a non-GAAP measure). See Non-GAAP Financial Measures & Reconciliations. Figures may not sum due to rounding.

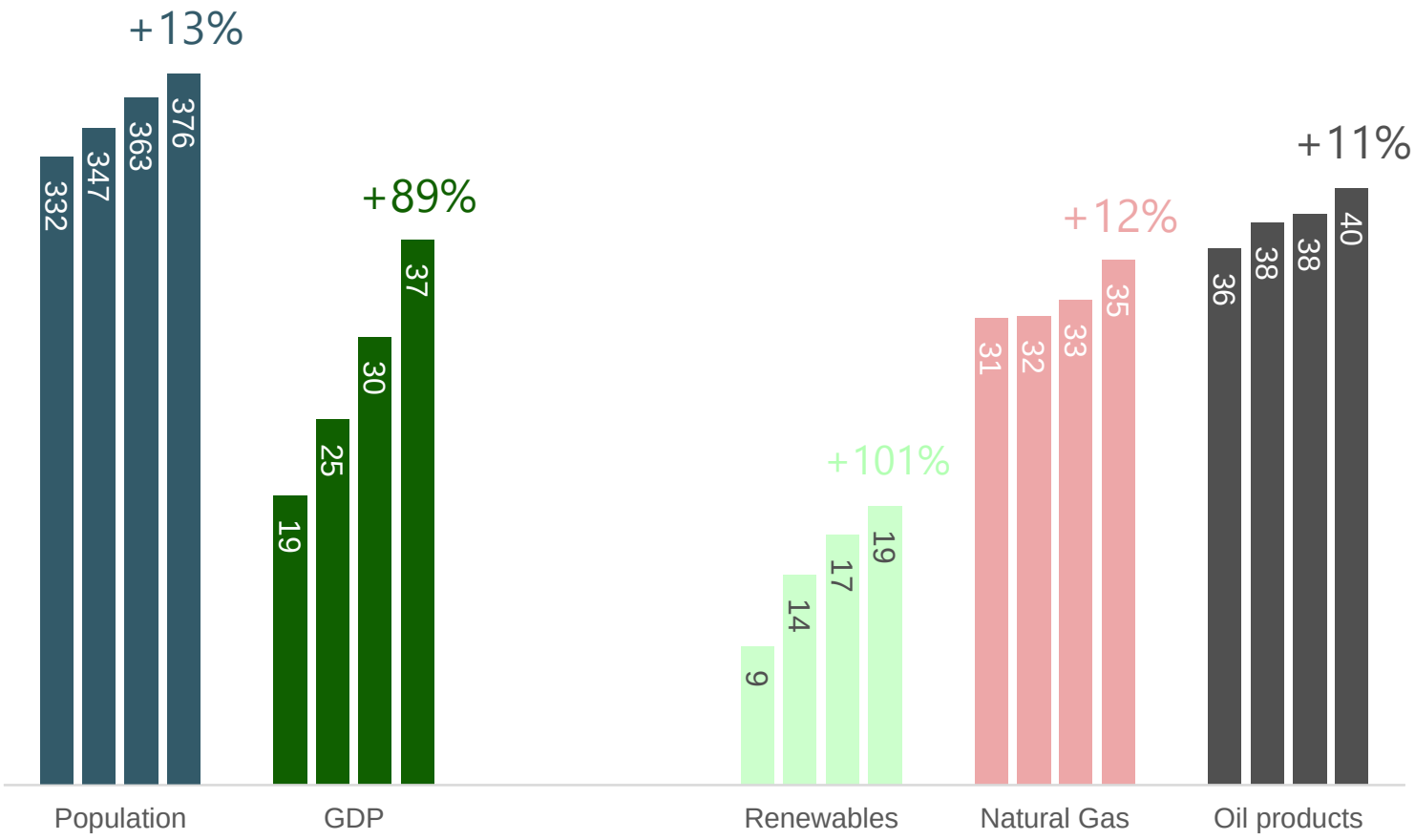
MARKET FUNDAMENTALS

CIG Rawlins station, Sinclair, Wyoming

Energy is Essential to Human & Economic Development

The transition to a renewable-energy world will not be seamless and will require the ongoing use of hydrocarbons

U.S. POPULATION, GDP & ENERGY DEMAND BY SELECT FUEL TYPES
2021, 2030, 2040, 2050



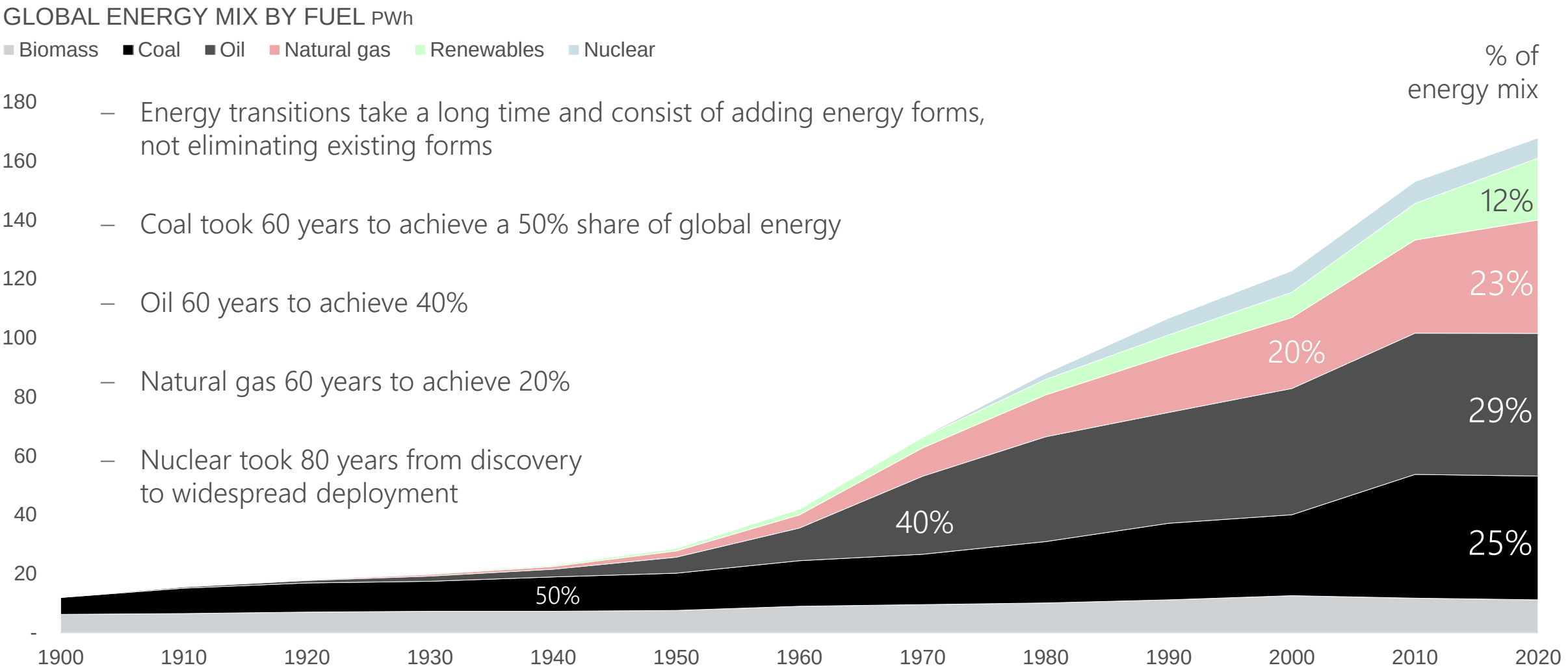
Hydrocarbons have significant advantages & are irreplaceable in certain applications: cement, steel, fertilizer, plastics

These are materials that are needed for a growing population and a rising standard of living

Note: U.S population in million people. U.S. GDP in trillion USD. Renewables, natural gas, and oil products in quadrillion btu.
Source: EIA 2022 Annual Energy Outlook.

Energy Transitions Take Time

Our assets and services will be needed for a very long time

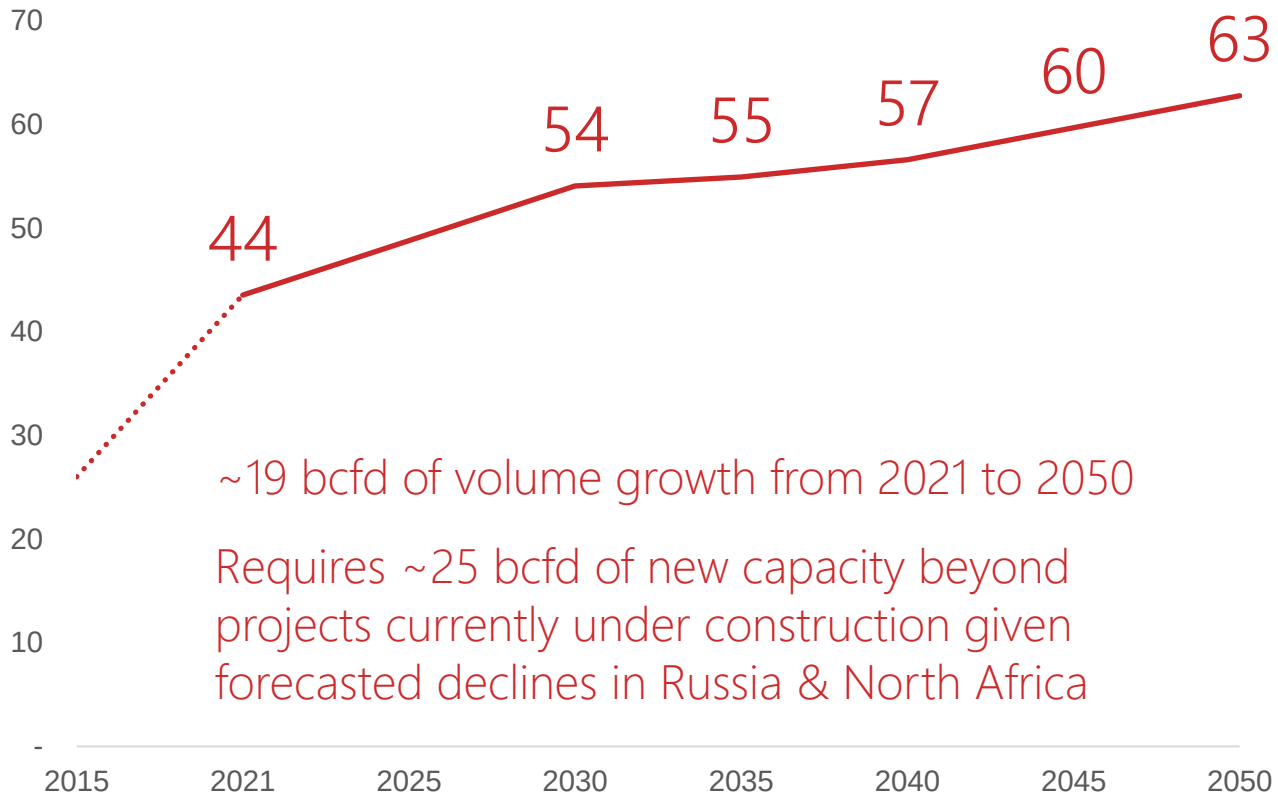


Source: Pre-1965 from *Energy Transitions: Global and National Perspectives*; 1965 and beyond from BP's Statistical Review of World Energy.

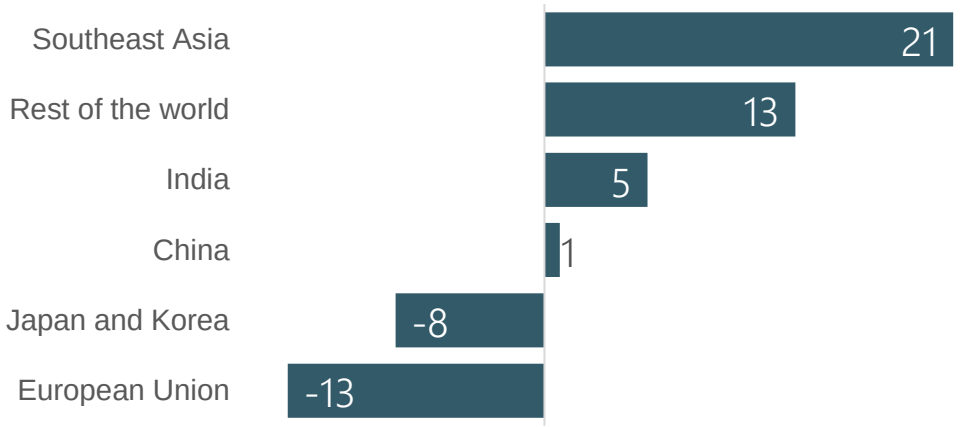
Significant Additional LNG Capacity Will Be Needed to Meet Future Demand

US & Middle East account for ~75% of LNG supply growth to 2050

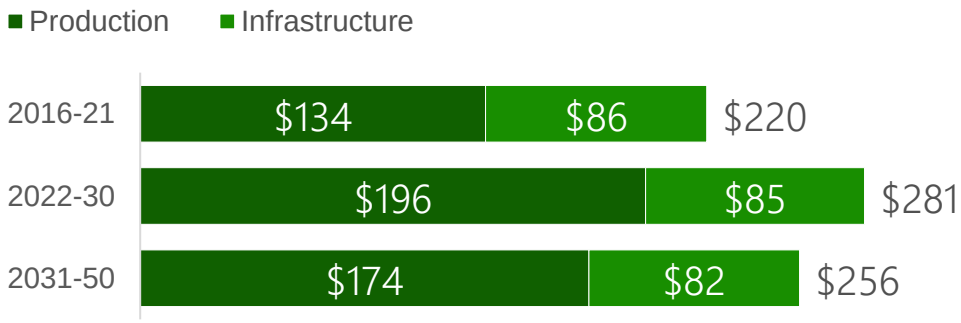
GLOBAL LNG VOLUMES bcfd



2021–2050 LNG IMPORT DEMAND GROWTH bcfd



AVERAGE ANNUAL LNG SPEND $billion

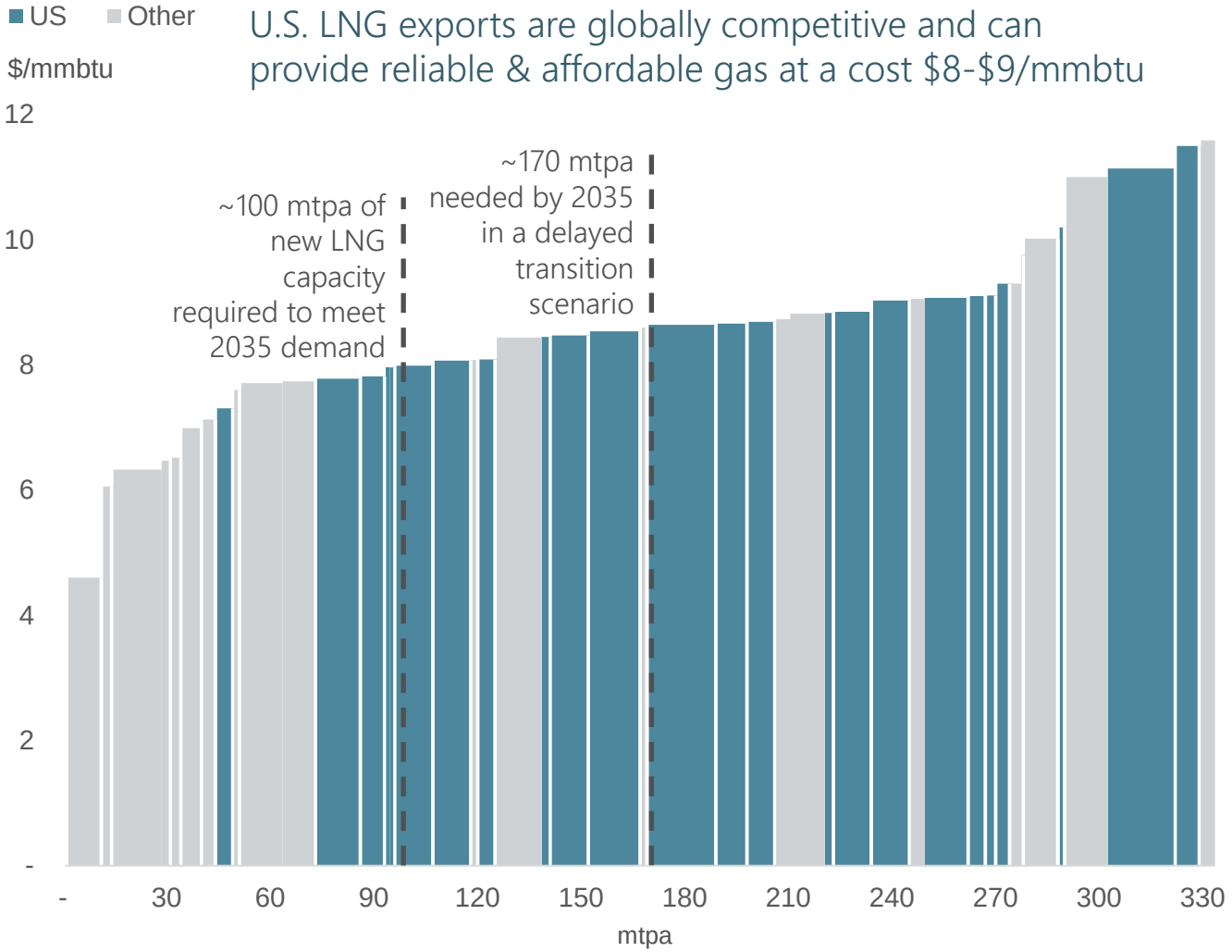


Based on IEA data from the IEA (2022) World Energy Outlook, World Energy Outlook 2022 – Analysis – IEA. All rights reserved; presentation modified by Kinder Morgan (data unchanged). STEPS (Stated Policies) scenario. Infrastructure spend includes liquefaction and regasification terminals, ships, pipelines and storage. IEA does not provide a 2025 projection. 2025 data point is an extrapolation of the straight-line IEA projection from 2021 to 2030.

U.S. Expected to Support Increasing Global Demand

Reliable trade partner with ample reserves & price-competitive production

FULL CYCLE COST OF LNG PROJECTS



U.S. proved natural gas reserves increased 32% in 2021

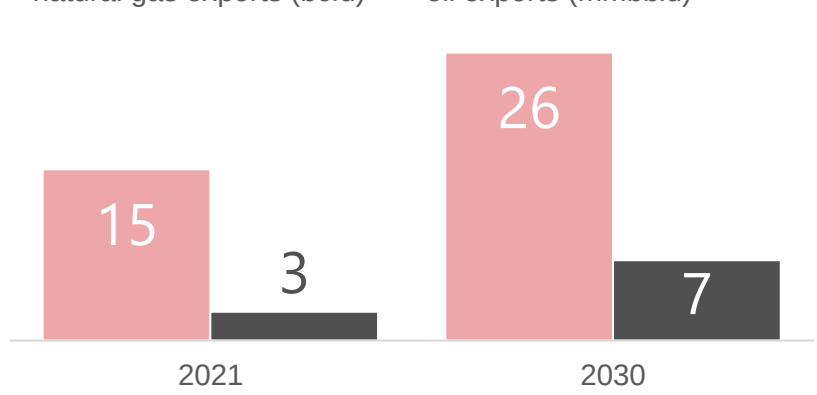
U.S. NATURAL GAS

2,926 tcf
total reserves
or
88 years
of production

U.S. OIL

373 bbo
total reserves
or
91 years
of production

U.S. EXPORTS



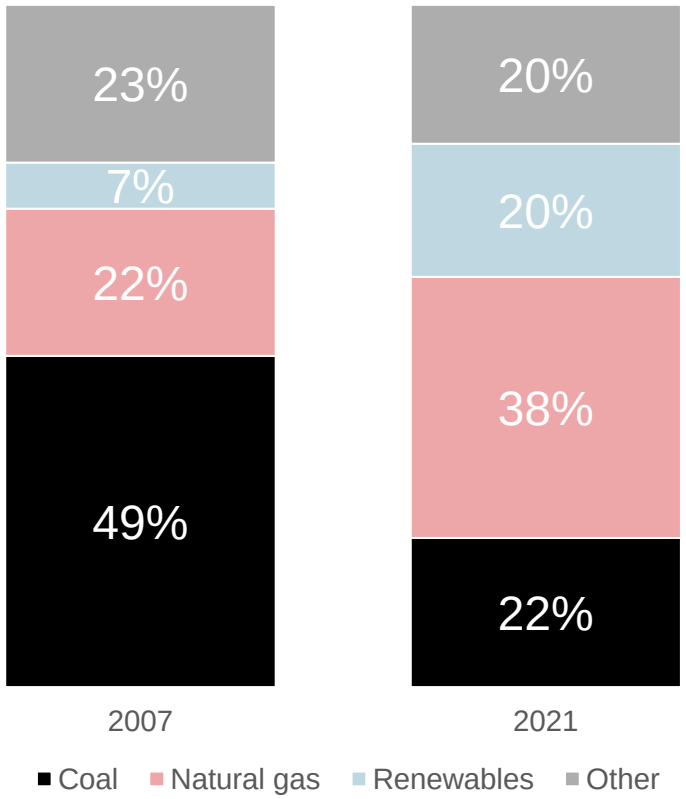
LNG project costs based on McKinsey Energy Insights analysis. LNG projects currently facing severe difficulties in terms of technology, sanctions, or stakeholder alignment (including Russian, Iranian and Mozambique projects) are excluded. Exports based on IEA data from the IEA (2022) World Energy Outlook, World Energy Outlook 2022 – Analysis – IEA. STEPS (Stated Policies) scenario. Total reserves based on EIA data and include proved, probable, and possible reserves. Years of remaining production calculated based on 2020 U.S. production.

U.S. CO_2 Emissions Declined Since 2007 while GDP grew ~45%

Primarily due to converting coal power generation to natural gas generation

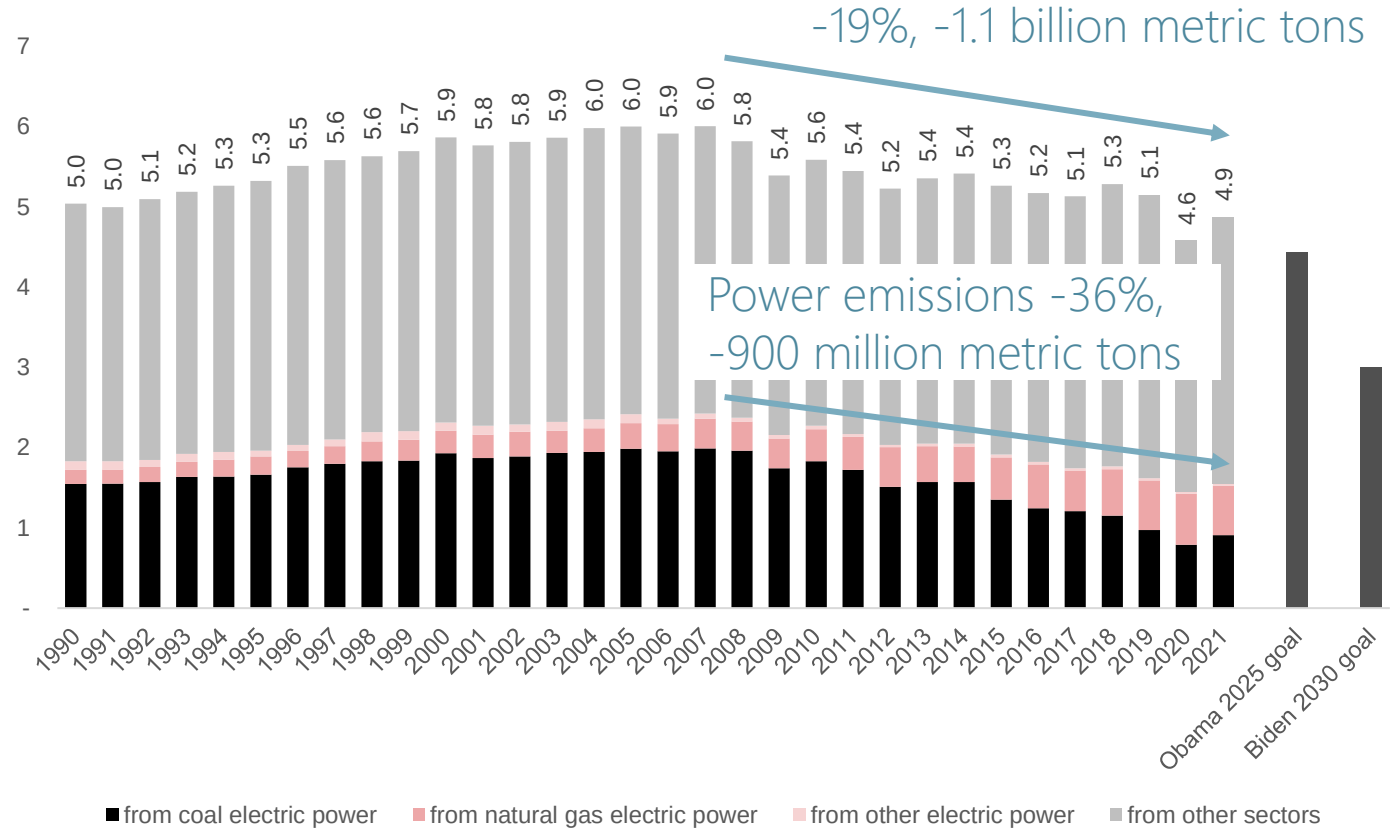
U.S. ELECTRICITY GENERATION MIX

% of total generation



U.S. CO_2 EMISSIONS FROM ENERGY CONSUMPTION

billion metric tons



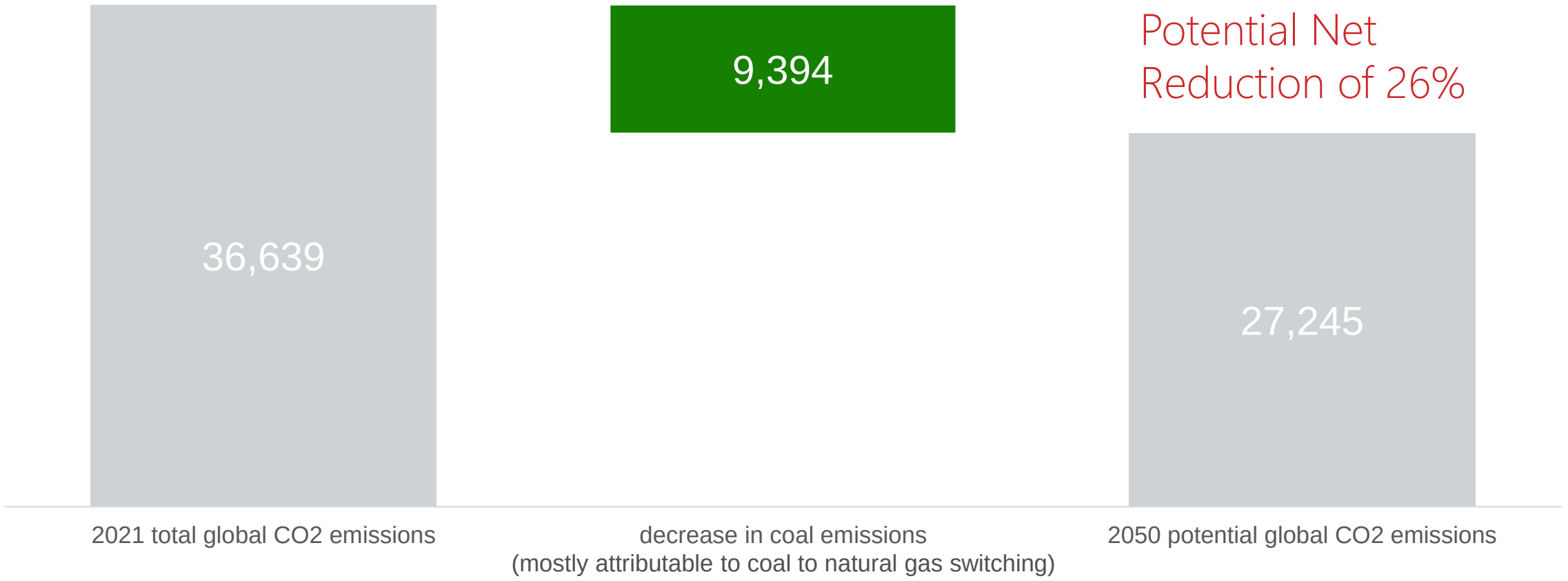
Under the original Paris Agreement, U.S. was to reduce 2005-level CO_2 emissions 26-28% by 2025

2/3 of that reduction goal was already achieved by 2021

Source: U.S. EIA Electricity Data Browser (net generation) & Monthly Energy Review (April-2022); World Bank, Development Indicators, GDP, U.S.$ current.

Replacing Coal Could Likewise Accelerate Global Emissions Reductions

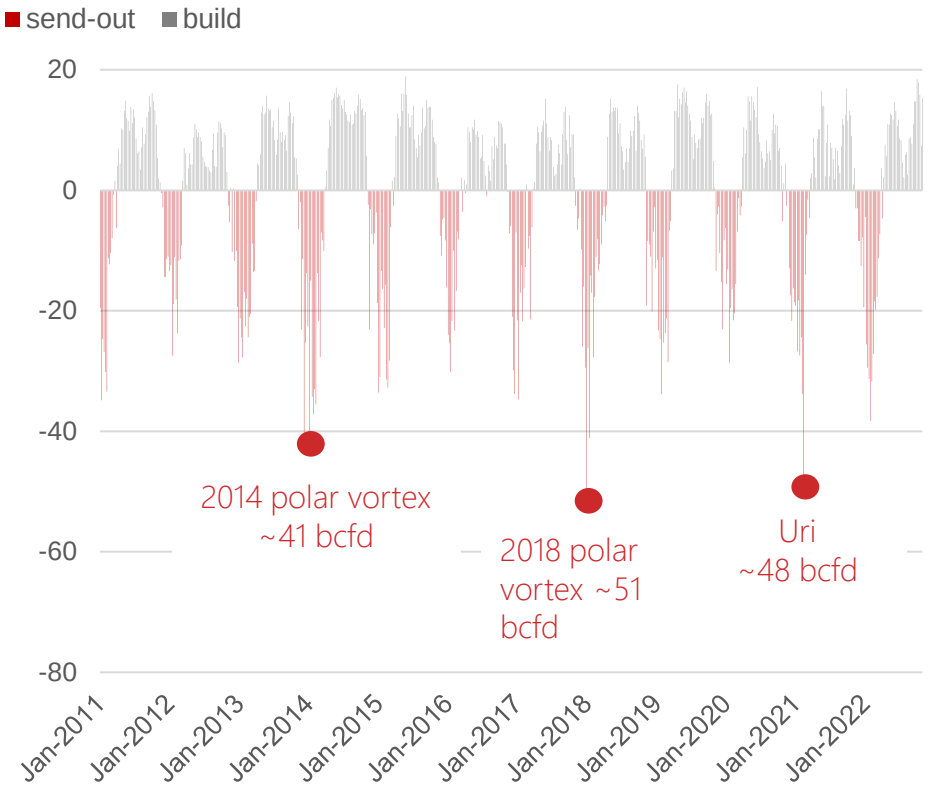
POTENTIAL FOR LOWER GLOBAL EMISSIONS Mt CO_2



Based on IEA data from the IEA (2022) World Energy Outlook, World Energy Outlook 2022 – Analysis – IEA. All rights reserved; presentation modified by Kinder Morgan (data unchanged). STEPS scenario. The STEPS scenario assumes coal emissions decrease 5,243 Mt CO_2 by 2050. A further 4,150 Mt CO_2 could be reduced by replacing coal with natural gas. This figure is calculated by dividing 2050 coal emissions of 9,863 Mt CO_2 by a coal emission intensity rate of 88 Mt CO_2/EJ, then multiplying by a natural gas emission intensity rate of 51 Mt CO_2/EJ. This yields an equivalent 2050 natural gas emissions figure of 5,713 Mt CO_2. Potential additional emissions reduction is difference between 9,863 Mt CO_2 and 5,713 Mt CO_2.

Reliable, Long-Duration Storage is Critical in Peak Demand Periods

DAILY AVERAGE OF WEEK-OVER-WEEK CHANGES IN U.S. WORKING GAS bcfd



Peak weather events have historically required 40 – 50 bcfd of natural gas storage send-out

DAILY POWER EQUIVALENT TWh per day

6.1

50 bcfd natural gas storage send-out

2050 U.S. APS forecasts only ~1.5 TWh of daily battery capacity

Reliability is critical during these weather events & batteries would have to be recharged the following day – assuming weather conditions permit

1.5

U.S. 2050 battery capacity under APS

Left: EIA Weekly Underground Natural Gas Storage Report. KM analysis.
Right: Based on IEA data from the IEA (2022) World Energy Outlook, World Energy Outlook 2022 – Analysis – IEA. All rights reserved; presentation modified by Kinder Morgan (data unchanged). APS = Announced Pledges Scenario.
Note: Battery equivalent based on natural gas energy converted terawatt hours (TWh) at 0.29 TWh per day per 1 bcfd; then, energy storage converted into power equivalent using assumed 42% efficiency rate of a natural gas peaker plant. Battery storage capacity assumes 4-hour duration by multiplying capacity by 4. IEA utility-scale battery storage assumptions range from one to eight hours.

Positioned for the Future of Energy

Our vast network of strategically-located energy infrastructure will continue delivering energy for decades to come

Moving fuels of today

U.S. is the world's most responsible producer of scale

U.S. exports help meet global demand from emerging economies in need of affordable, modern energy

Natural gas can rapidly lower emissions from the global power & industrial sectors, which still rely heavily on coal

Flexible storage & delivery of natural gas facilitates increased use of renewables while avoiding power outages

Our assets facilitate renewable blends with traditional fuels

& the future

Building new infrastructure networks is difficult, environmentally impactful & costly; existing assets are likely to remain valuable

Some emerging renewable fuels can be moved on our assets today

Current pipeline & storage assets could be upgraded or repurposed to handle renewables, lower carbon fuels, or other transition-driven products

We will take a disciplined approach when evaluating new renewables opportunities

Essential to a clean, reliable, affordable energy future

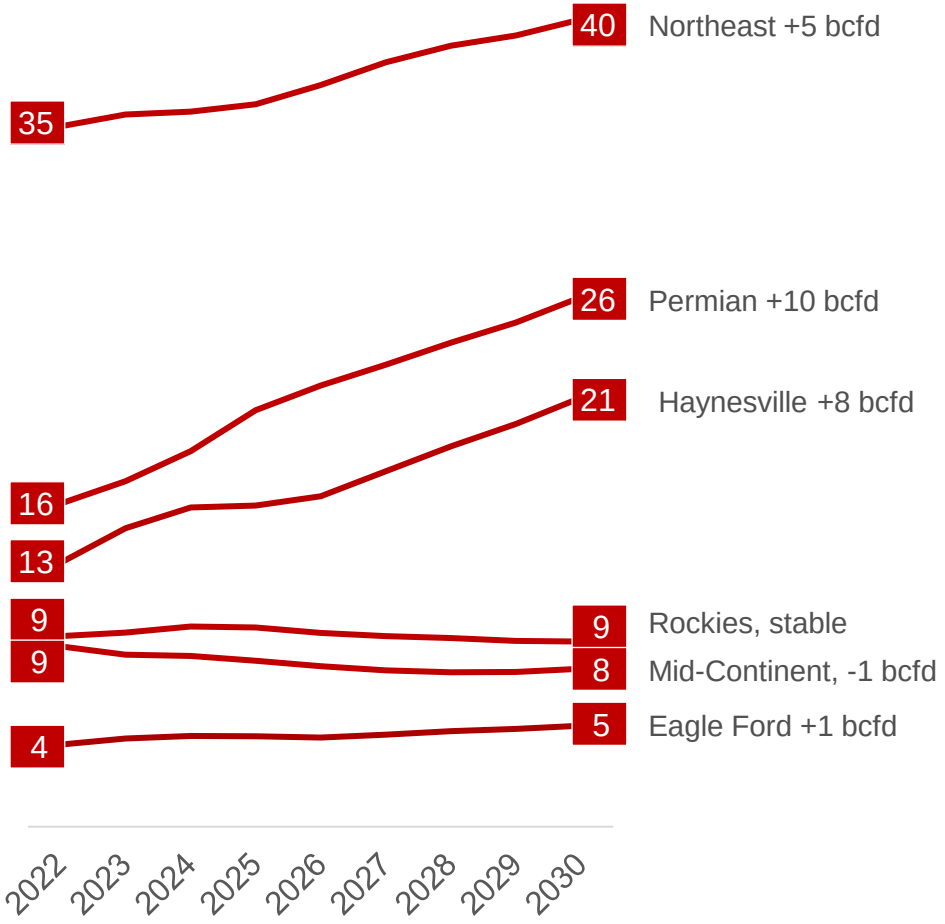
VALUABLE NETWORKS

Tall Cotton compressor station, Seminole, Texas

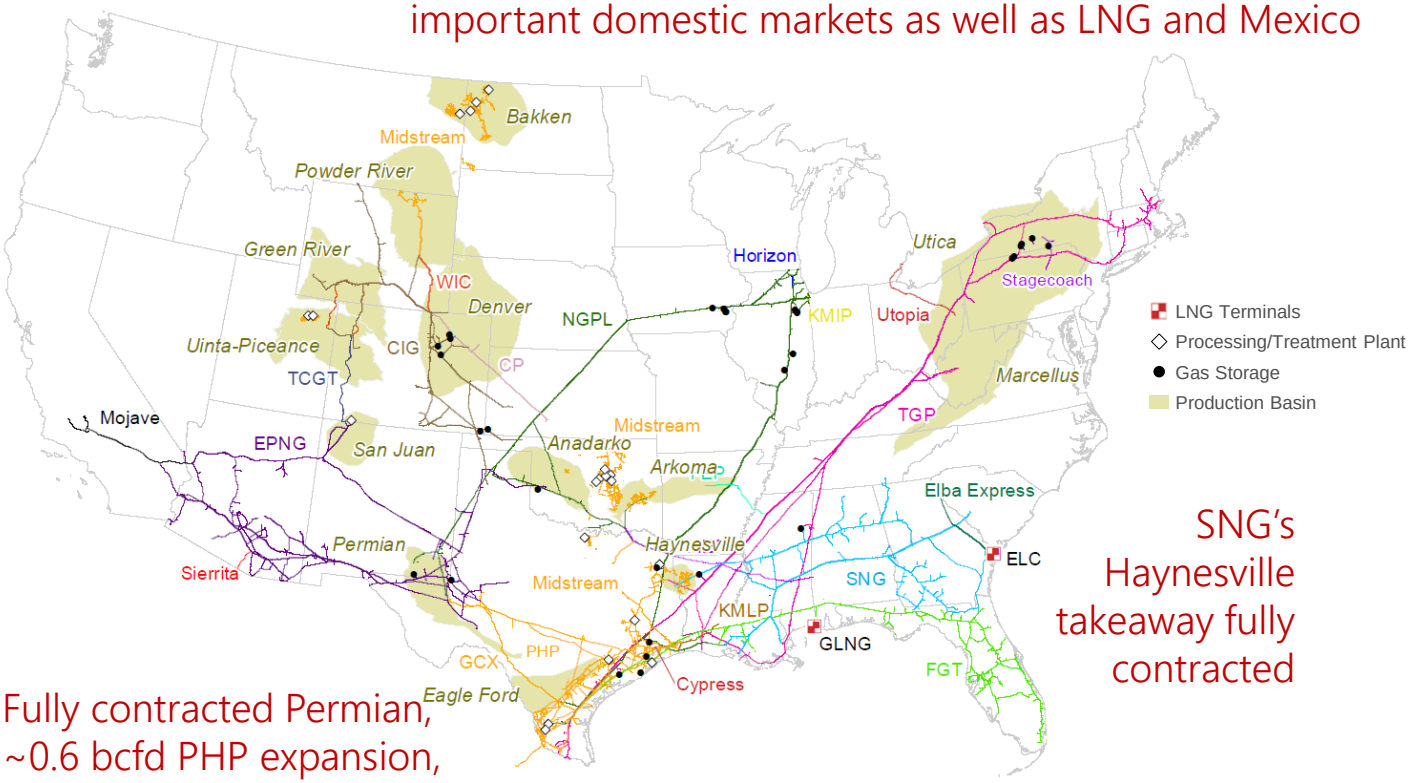
Provide High-Value Natural Gas Takeaway in all Major Basins

U.S. production expected to grow 20% by 2030

U.S. NATURAL GAS PRODUCTION RELEVANT TO OUR FOOTPRINT bcfd



TGP provides valuable egress for NE producers & serves important domestic markets as well as LNG and Mexico



SNG's Haynesville takeaway fully contracted

Fully contracted Permian, ~0.6 bcfd PHP expansion, and evaluating additional opportunities

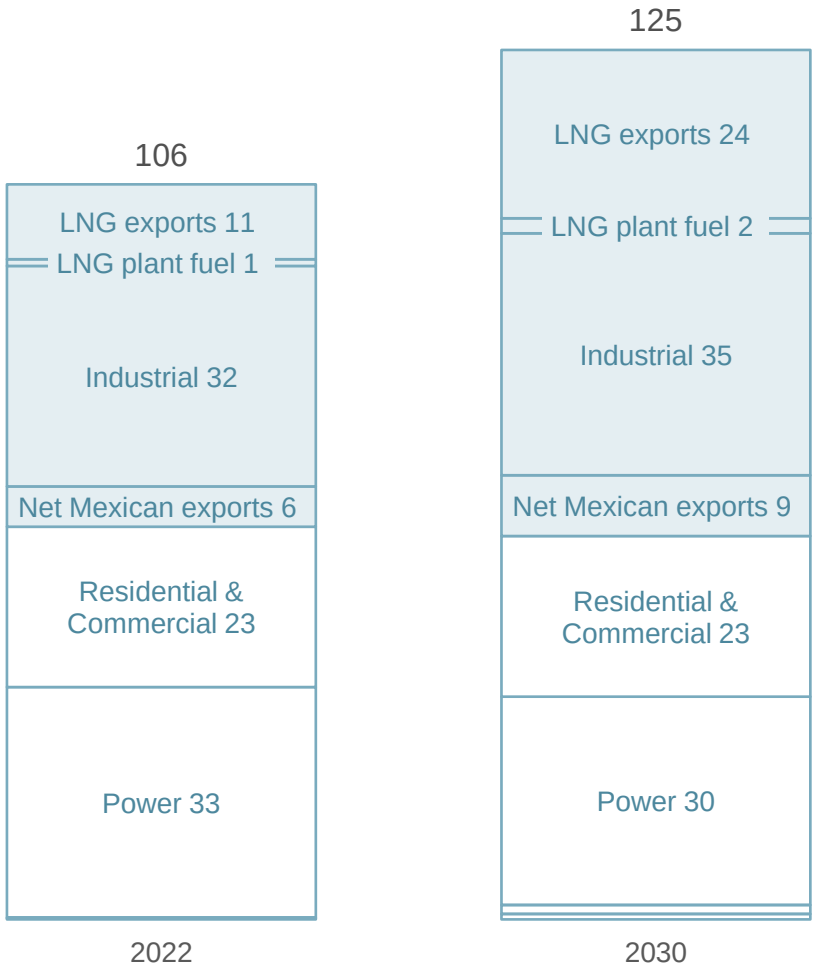
Kinderhawk gathering system – additional growth through efficient capital expansions

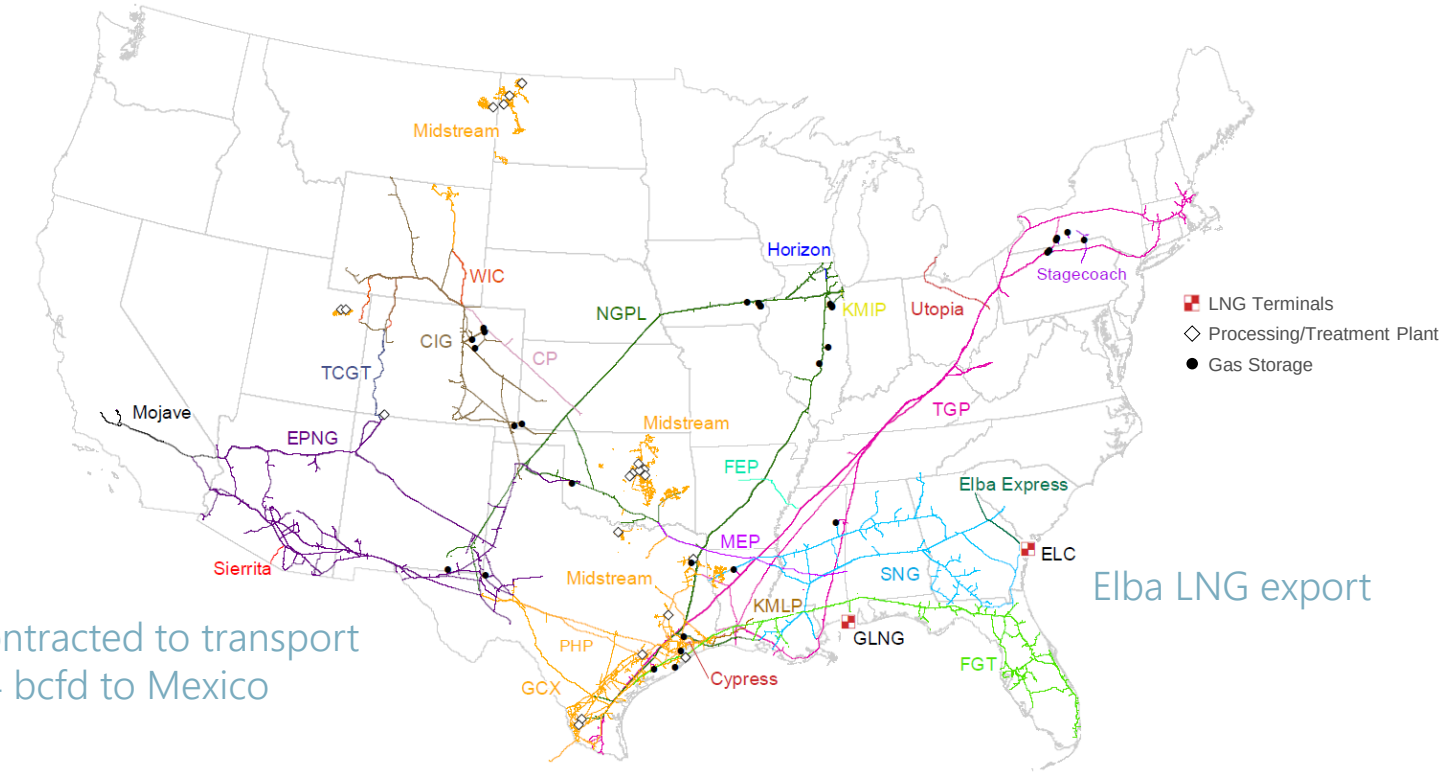
Source: WoodMackenzie, North America Gas 10-year Investment Horizon Outlook, October 2022.
Note: Rockies predominately includes production from the Niobrara, Powder River, Bakken, Three Forks formations.

Strong Gulf Coast Footprint Positioned to Serve Demand Growth

>95% of demand growth is expected to occur in Texas & Louisiana, driven by exports & industrial

U.S. NATURAL GAS DEMAND bcfd





Contracted to transport ~4 bcfd to Mexico

Elba LNG export

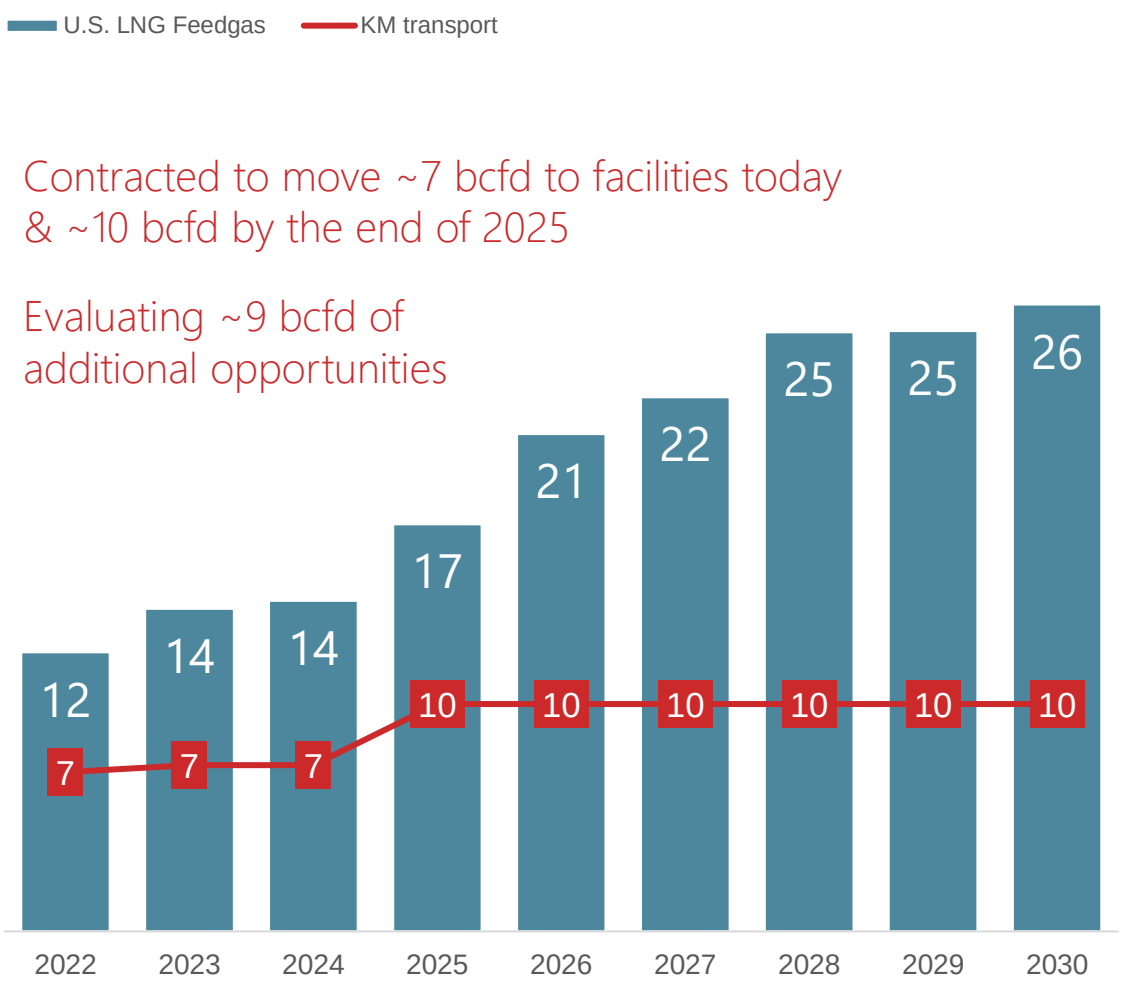
Intrastates system directly connects to petchem & industrial facilities all along the TX Gulf Coast

Contracted ~7 bcfd today across 5 pipes to LNG export facilities & evaluating additional opportunities

Source: WoodMackenzie, North America Gas 10-year Investment Horizon Outlook, October 2022. Industrial sector includes WoodMackenzie's "Other" category, comprised of lease and plant fuel. LNG plant fuel is assumed to be equal to 9% of LNG export volume. This volume would otherwise be included in the Industrial category. 2030 demand includes 2 bcfd attributable to Transport and Blue Hydrogen sectors.

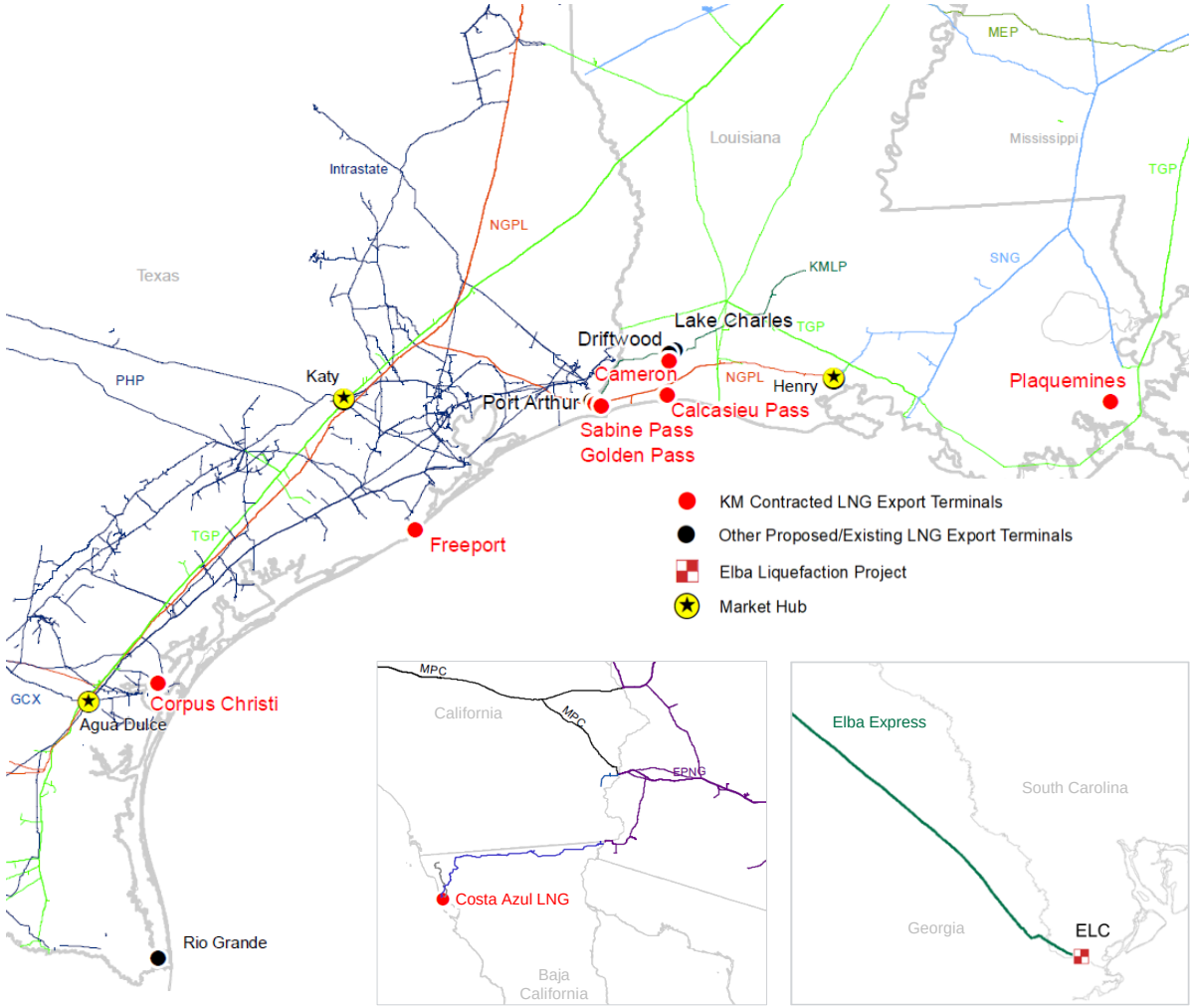
Transporter of Choice for LNG Facilities due to Supply Diversity, Network Connectivity, & 700 bcf of Total Working Gas Storage

U.S. LNG FEEDGAS & KM TRANSPORT POTENTIAL bcfd



Contracted to move ~7 bcfd to facilities today & ~10 bcfd by the end of 2025

Evaluating ~9 bcfd of additional opportunities



Source: WoodMackenzie, North America Gas 10-year Investment Horizon Outlook, October 2022.
Note: WoodMackenzie exports are multiplied by 1.09 for an estimated feedgas figure.

Extensive Storage Capabilities & Premium Service Offerings Provide Valuable Solutions for Variable Demand from Utilities & Exports

Largest storage position in U.S. with 700 bcf of storage

Multi-turn storage facilities provide customers with flexibility

Key to supporting daily & seasonal variability from LDCs & power, LNG facilities, Mexico, and intermittent renewables

For power grids with a higher mix of renewables, we offer premium services that help support volatile demand swings

- Pipe, storage & compression provide for hourly peak demand & duration
- Pressure guarantees, no-notice takes
- Economic & physical incentives for adequate contracting / nominations

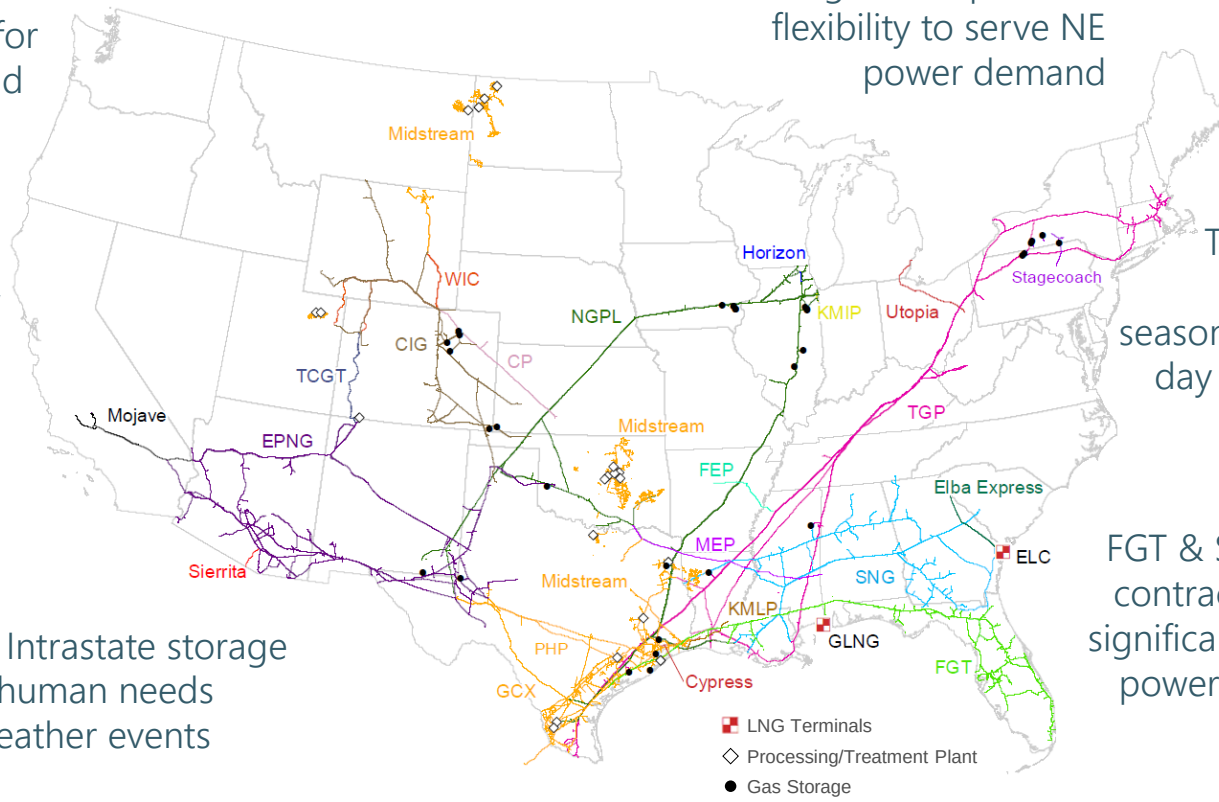
Non-ratable services are priced higher than ratable service, reflecting associated infrastructure use

CIG fully contracted for LDC & power demand along the Colorado Front Range

Stagecoach provides flexibility to serve NE power demand

Highly utilized & fully contracted EPNG serves CA & AZ power demand

TGP provides significant seasonal and peak day deliveries to NE markets



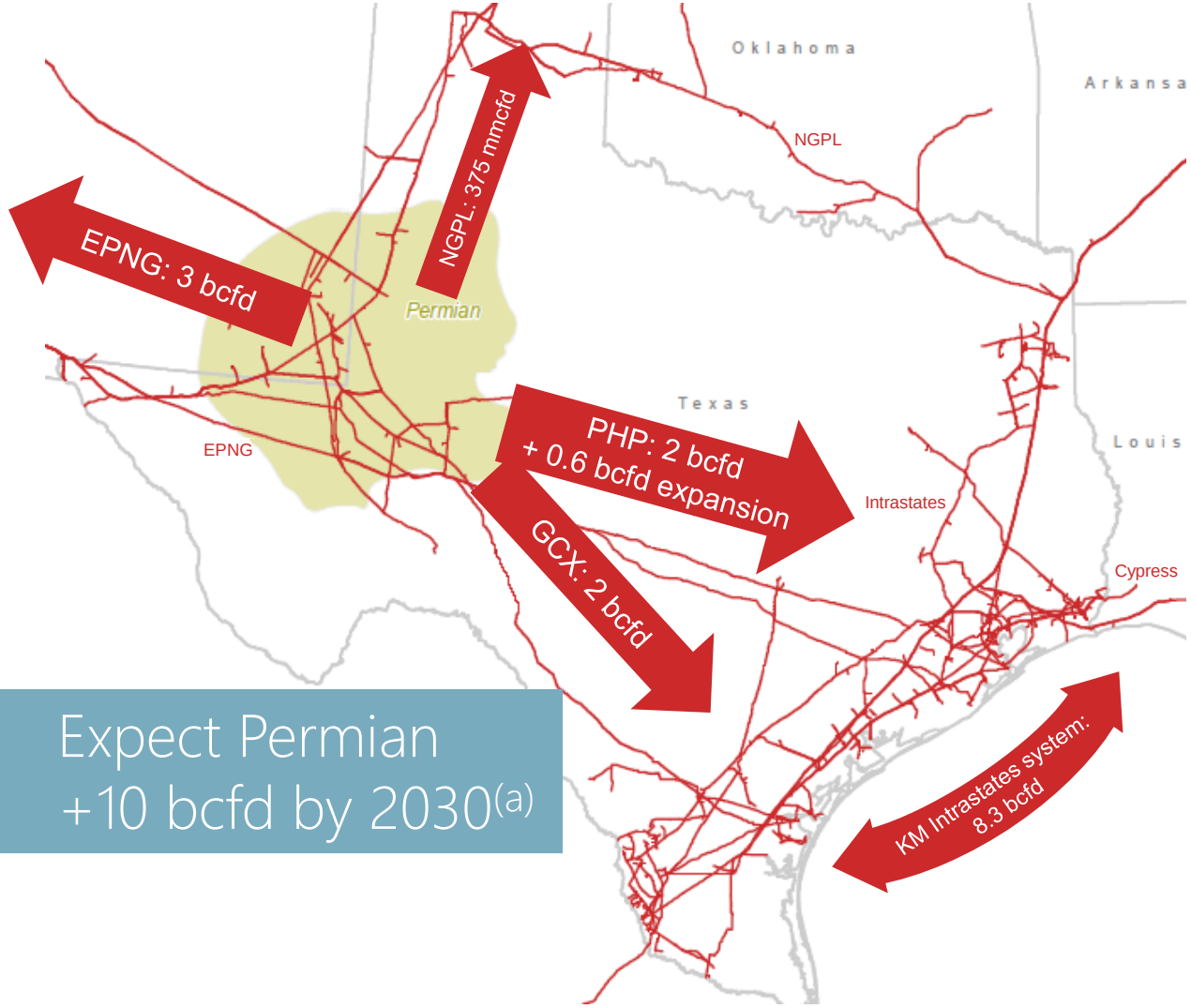
FGT & SNG fully contracted with significant LDC & power demand

Highly responsive Intrastate storage critical to serving human needs during extreme weather events

Storage supports daily & seasonal variability in exports to Mexico, where minimal storage exists

Storage is key for LNG facilities which face interruptions from cargo scheduling changes, maintenance, & weather

Continue to Serve the Permian's Growing Gas Takeaway Needs



Expect Permian
+10 bcfd by 2030[a]

Own interest in >7 bcfd of existing Permian takeaway capacity

Highly utilized capacity with long-term contracts

Advantaged Intrastates network, downstream of GCX and PHP, provides shippers with end-market optionality (Houston power & petchem, LNG exports, Mexico exports)

Expanding recently-built PHP by 550 mmcfd

Capital-efficient project primarily adding compression

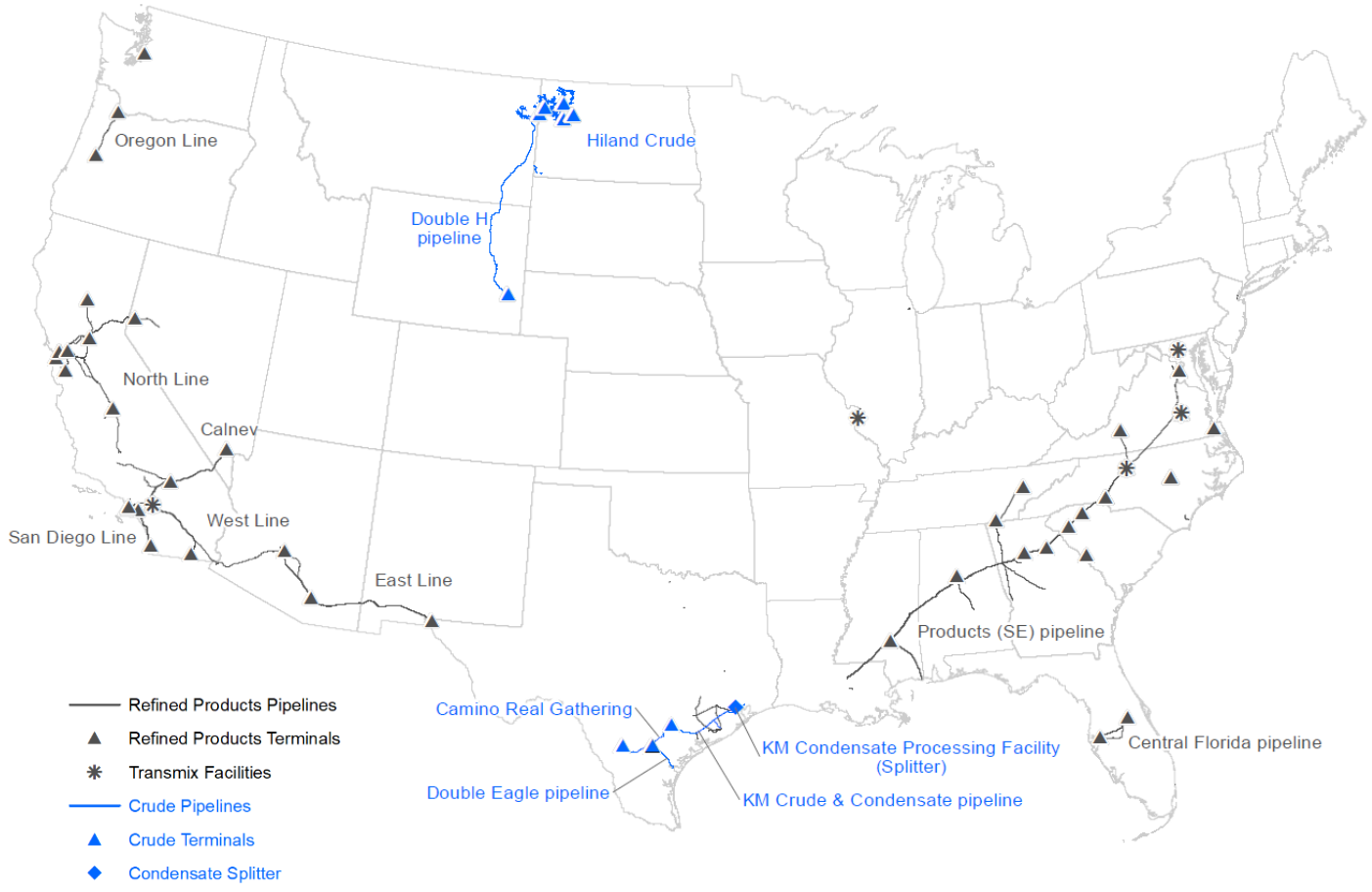
Provides speed to market, with November 1, 2023, target in-service date

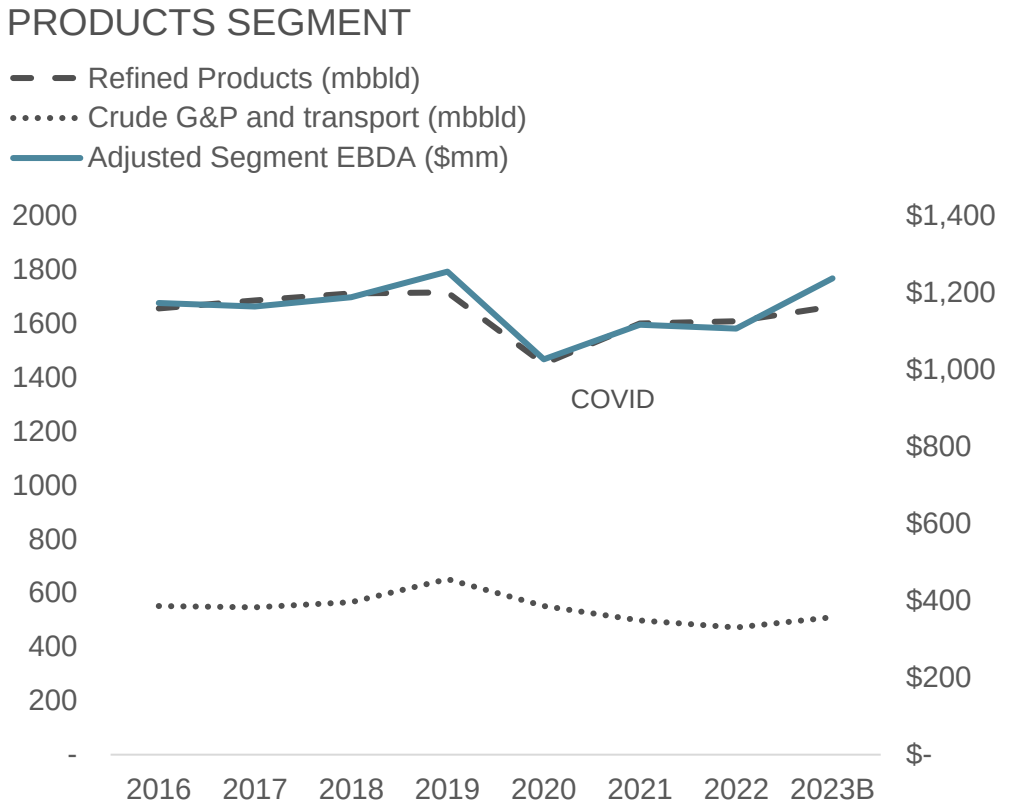
Evaluating additional Permian transport opportunities

a) Compared to 2022. WoodMackenzie, North America Gas 10-year Investment Horizon Outlook, October 2022.

Products Segment Overview

Refined products pipes deliver transportation fuels from refining centers to key demand markets; crude assets in major basins





long-term steady volumes & cash flow

Renewable diesel projects help maintain west coast diesel market share on pipelines and enable expanded rack blending opportunities at the terminals

FERC rate escalator on refined products pipes helps protect rates relative to cost inflation

Note: Adjusted Segment EBDA is a non-GAAP measure. See Non-GAAP Financial Measures & Reconciliations.

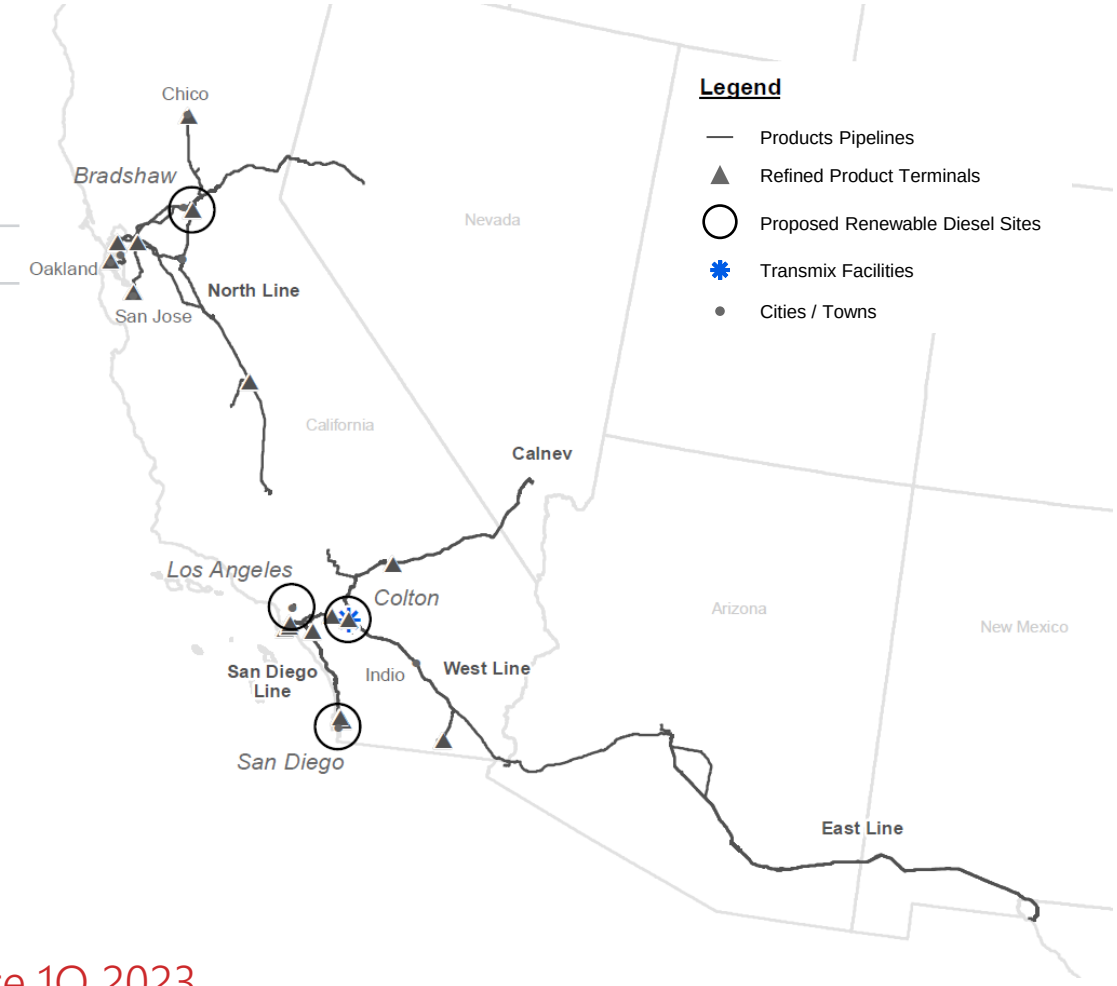
Products Segment's West Coast Renewable Fuels Projects

Subsidies & state goals for emissions reductions are driving increased RD volumes

Particularly in California where stacked subsidies currently average ~$4.00/gal (RIN+LCFS+BTC)

Expanding our renewable fuel handling capabilities:

Project	Project Description
– Northern CA RD by pipeline	
Bradshaw (Sacramento)	Providing 6 mbbld R99 capacity at truck rack
San Jose	Providing 5 mbbld R99 capacity at truck rack
Fresno	Providing 10 mbbld R99 capacity at truck rack
– Carson RD (Port of LA)	Converting ~500 mbbls storage capacity to RD Providing 15 mbbld R99 capacity at truck rack
– Southern CA RD blending	
Colton (inland)	Increasing blend capabilities to 20% Providing 15 mbbld blended diesel capacity at truck rack
Mission Valley (San Diego)	Providing 5 mbbld R99 capacity at truck rack
– Richmond RD (Bay area)	Converting ~60 mbbls storage capacity to RD Providing 15 mbbld blended diesel capacity at truck rack



Investing ~$73 million

Expect majority of Southern CA and Northern CA projects in-service 1Q 2023

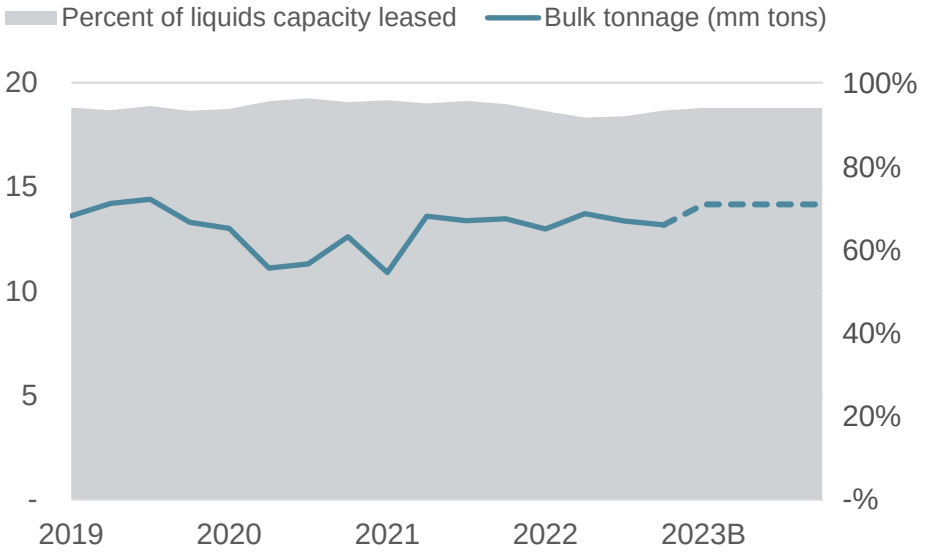
Potential for additional expansion opportunities, including RD feedstock logistics

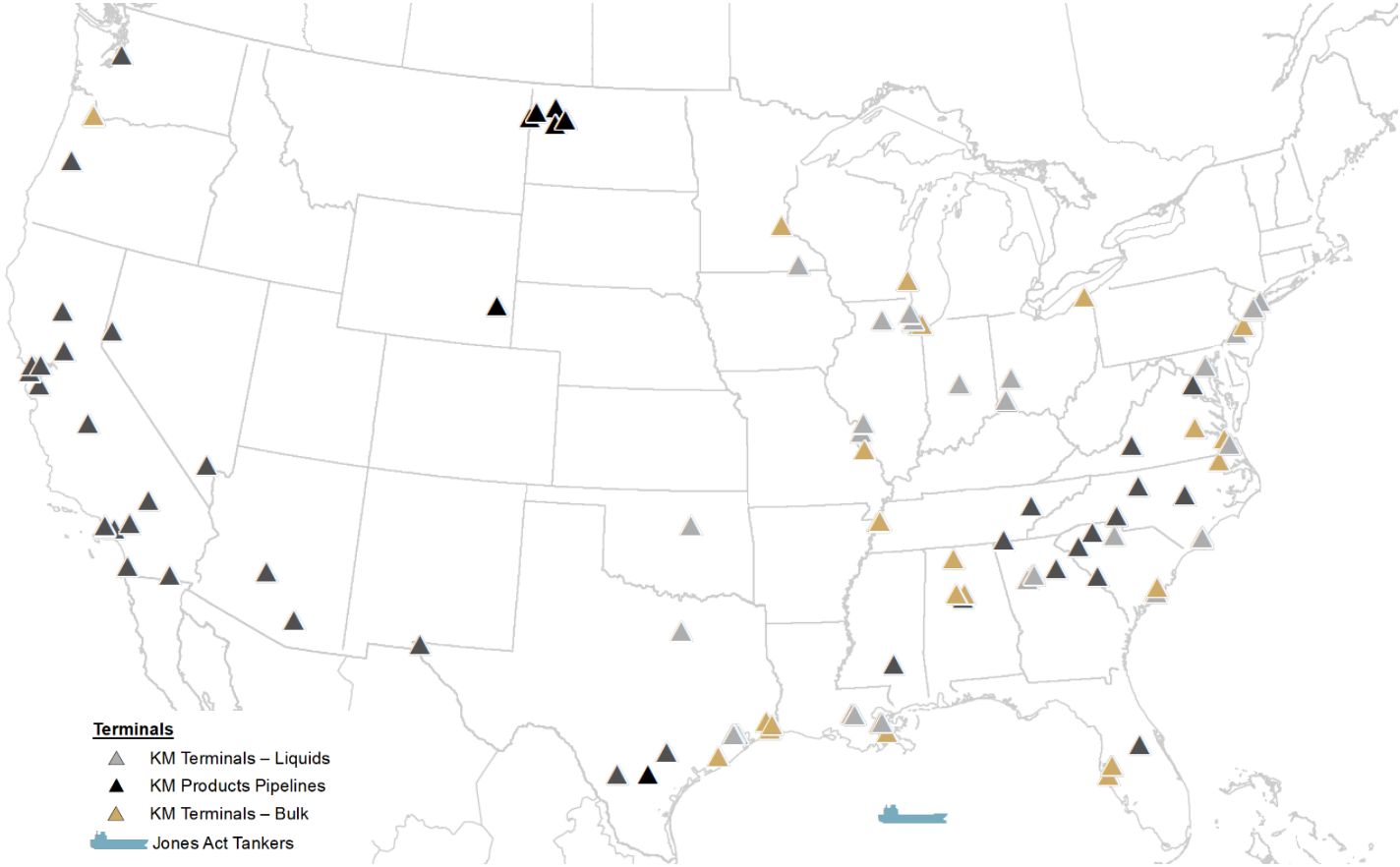
Terminals Segment Overview

Refined products focused; providing customers with unmatched scale, service-offerings & market-making connectivity

ASSET SUMMARY	# of terminals	capacity (mmbbls)
Terminals segment – Bulk	28	
Terminals segment – Liquids	47	78
Products segment	65	56
Total Terminals	140	134
Jones Act:	16 tankers	

TERMINALS SEGMENT VOLUMES & UTILIZATION





Tankers Meeting Domestic Maritime Demand

Most modern & efficient Jones Act tanker fleet

American Petroleum Tankers

- 16 fuel-efficient Jones Act tankers
- Largest, most modern fleet with an average age of 8.8 years

Dramatically improved Jones Act fundamentals

- Industry supply & demand dynamics have tightened considerably with 100% of the fleet presently utilized
- Trade flow disruptions for both crude and products associated with Russia/Ukraine crisis
- Nascent trans-Panama Canal trade for RD from USGC to USWC
- New statutory limitations on issuing waivers

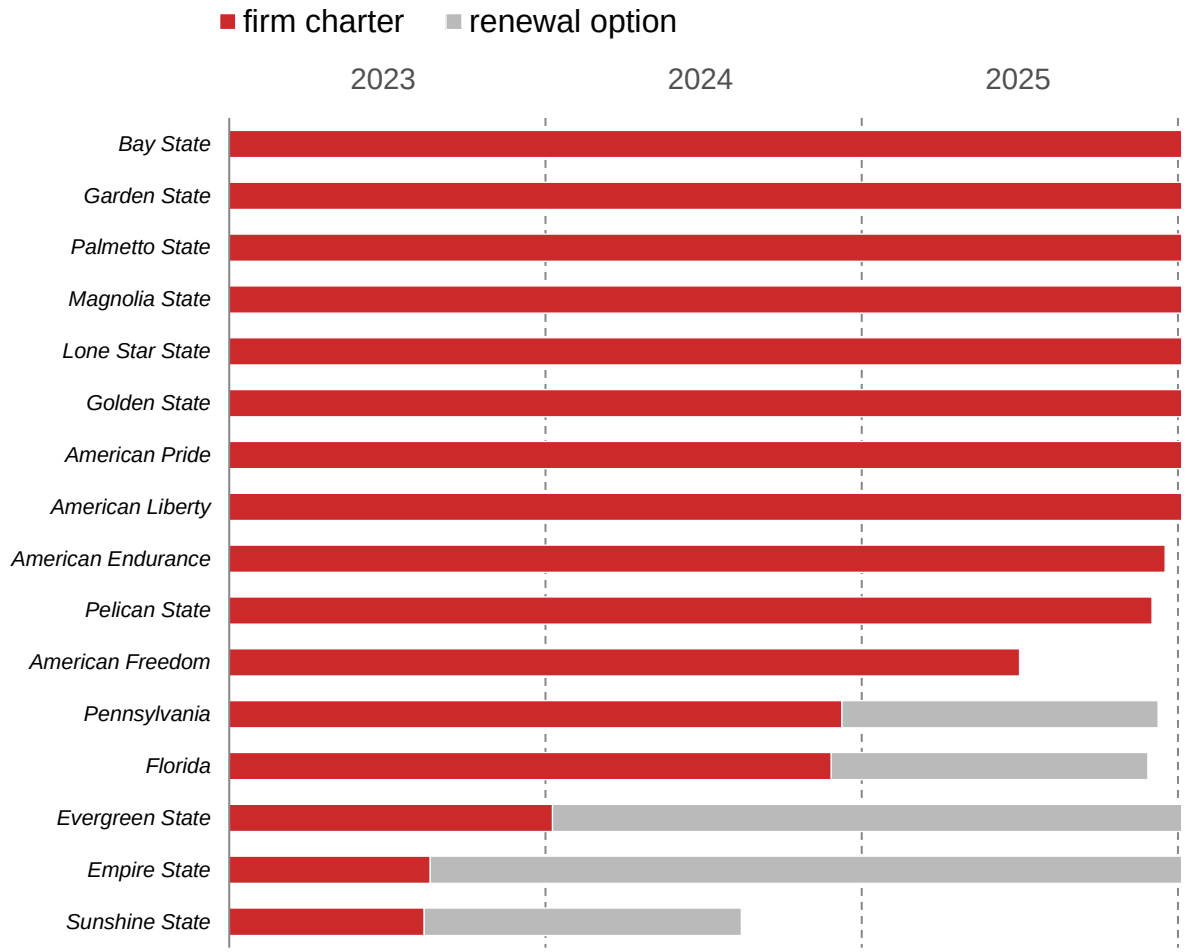
Strengthening charter rates further supported by new-build economics

- Spot time charter rates for Medium Range (MR) Jones Act tankers have improved from $58K/day at the end of 2021 to $75K/day today[(a)]
- New-build MR capital cost estimated ~$200MM/vessel with earliest potential deliveries in 2027[(a)]
- Term charter rate required to underwrite such investment estimated at ~$100K/day[(a)]

Significantly de-risked APT charter profile

- Percent of revenue days under firm charter:

	2022	2023	2024	2025
As of Jan 2022	72%	19%	25%	25%
As of Jan 2023	100%	93%	79%	65%



Average firm charter term remaining has improved from 1.3 years at the beginning of 2022 to 3.3 years today

a) Source: Wilson Gillette Report, December 2022 by Navigistics Consulting.
b) Revenue Days calculated as 16 vessels x 365 days, adjusted for scheduled dry docks.

Industry-Leading Renewable Feedstock Storage & Logistics Offering

Expanding Lower Mississippi River Hub

Modifying 30 tanks & enhancing rail, truck, and marine capabilities for Neste at Harvey

$80 million capex

1Q 2023
operational

657 mbbl capacity
can expand further

- Our flexible terminaling network improves efficiency & sustainability of NESTE supply chain
- Network scale can keep pace with NESTE's RD feedstock growth
- Handle other renewable volumes for NESTE including:
  - Feedstock in Midwest & Northeast
  - SAF at Galena Park

New heated storage capacity and various marine, rail, & pipeline infrastructure improvements at GRT

$52 million capex

4Q 2024
operational

247 mbbl capacity

- Constructing a new steam-traced and insulated outbound pipeline connection to nearby RD plant
- KM's Geismar River Terminal is strategically positioned to meet the growing feedstock requirement of the plant
- Supported by a long-term commercial commitment

Leveraging existing assets towards capital-efficient, attractive return opportunities supporting growing renewable fuels market

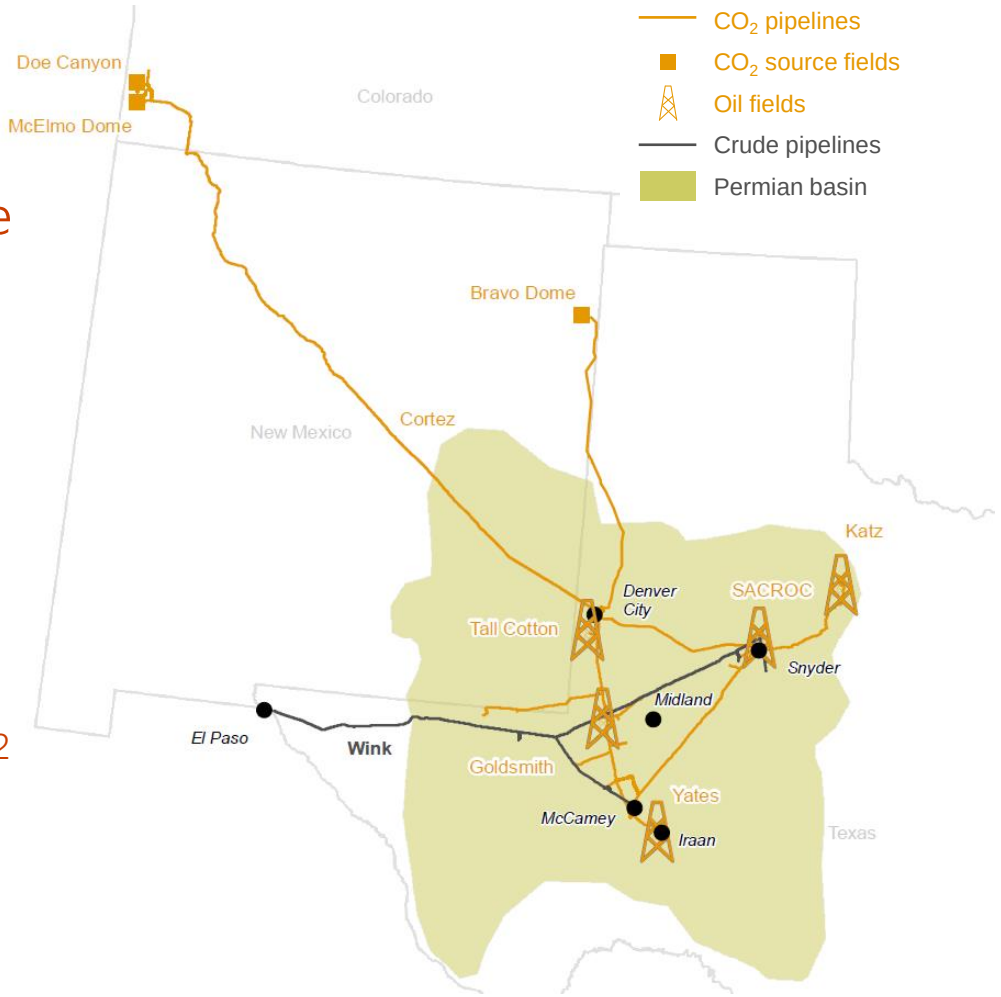
CO_2 Segment Overview

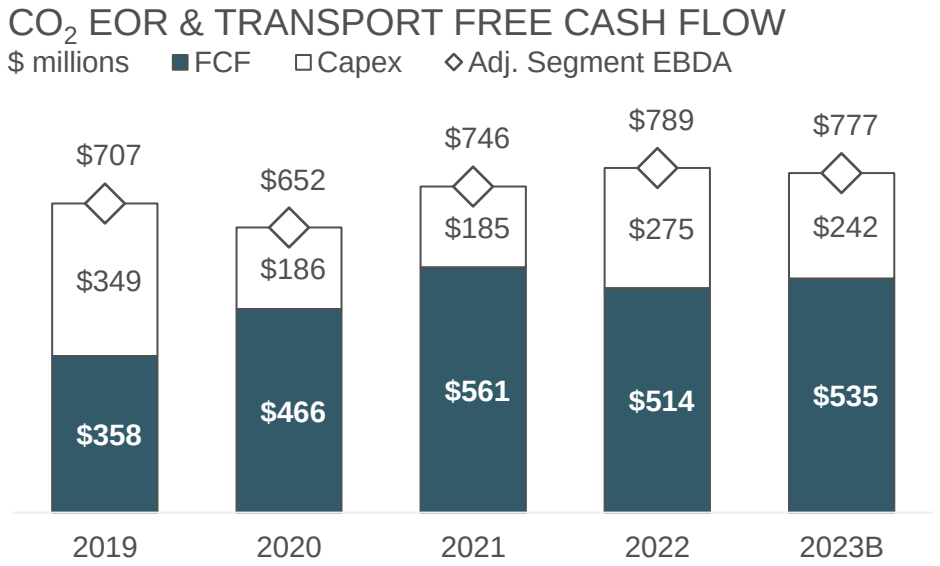
World class, fully-integrated assets | CO_2 source to crude oil production & takeaway in the Permian Basin

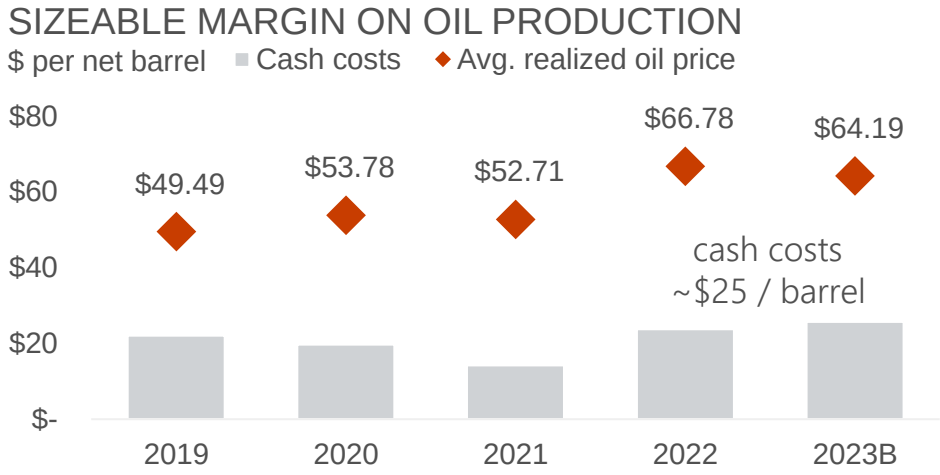
Interest in 5 oil fields with 9.2 billion barrels of Original Oil In Place

Interest in 3 CO_2 fields with 37 tcf of Original Gas In Place

~1,500 miles of CO_2 pipelines with capacity to move up to 1.5 bcfd







Note: CO_2 EOR & Transport FCF and Adjusted Segment EBDA are non-GAAP measures. See non-GAAP Financial Measures & Reconciliations. Cash costs & revenue per net oil barrel, including hedges where applicable. Cash costs exclude DD&A expense and primarily consist of expenses related to power, labor, rig work, CO_2 purchases, taxes other than income tax, and gas processing. Lower cash costs in 2021 were driven by a benefit from returning power to the grid.

RNG Portfolio Grows with 2022 Acquisitions

LANDFILL-RNG ANNUAL PRODUCTION CAPACITY net to KM	GROWTH PLAN	PRIMARILY CONTRACTED IN TRANSPORTATION MARKET TODAY
1.8 bcf operational (2.2 bcf gross)	Potential to grow +0.6 bcf over next decade with little capex	Long-term contracts in transportation/RIN market
+3.5 bcf expected online 2023	Up to ~$300 million development capex	Short term contracted into RINs market, optionality for RNG or eRINs on acquired assets
+up to 1.7 bcf 2024+		
=7.0 bcf (7.4 bcf gross)	Expect <6x 2024 Project EBITDA based on ~$1.1bn total RNG portfolio investment	Opportunity for fixed-price contracts will grow as voluntary market develops

7.4 bcf of RNG reduces emissions by 4.2 million metric tons CO_2 e per year, equivalent to:

9.7mm barrels of oil consumed

471mm gallons of gasoline consumed

carbon sequestered by 5mm acres of U.S. forest

Note: Project EBITDA is a non-GAAP measure. See Non-GAAP Financial Measures and Reconciliations.
Emission calculation and equivalencies based on the EPA's Landfill Gas Energy Benefits Calculator. We expect our plants to capture 15.9 bcf/year of feedgas to produce 7.4 bcf/year of RNG.

Red Cedar Carbon Capture and Sequestration

Utilizing KM's assets and expertise to enable an accretive CCS project

Overview

- Red Cedar Gathering (RCG) is a natural gas midstream joint-venture between Southern Ute Indian Tribe Growth Fund (51%) and Kinder Morgan (49%) in southern Colorado
- A term sheet has been executed and definitive agreements are being finalized between RCG and Kinder Morgan ETV to transport and permanently sequester CO_2

Scope

- RCG will install carbon capture equipment at two natural gas treating facilities with the ability to capture up to 400,000 metric tons per year of CO_2 and deliver the captured CO_2 to Kinder Morgan's existing Cortez pipeline
- Kinder Morgan will be responsible for transporting the CO_2 to an existing Kinder Morgan Class II well in the Permian Basin and permanently sequestering the CO_2

Project Details

- MRV plan has been submitted to the EPA as well as permit modifications to Texas Railroad Commission
- Net capital investment of less than $50 million
- Project returns competitive with traditional business
- Target in-service by Q2 2024

Ownership in RCG JV, existing CO_2 pipeline network, and downhole experience allow KM to participate in the entire CCS project value chain

Recognized as an ESG Leader

Highly rated by multiple agencies

improved ratings by publishing EEO-1 report and responding to CDP

FTSE #3

of Oil & Gas Pipelines subsector

MSCI A

Oil & Gas Refining, Marketing, Transportation & Storage Industry

Sustainalytics #3

of 114 Oil & Gas Storage & Transportation & #4 of 203 Refiners & Pipelines

Refinitiv #5

of 231 Oil & Gas Related Equipment and Services Companies

Moody's #2

of 43 Oil Equipment & Services North America

SSGA top 10%

R-Factor in Oil & Gas – Midstream sector

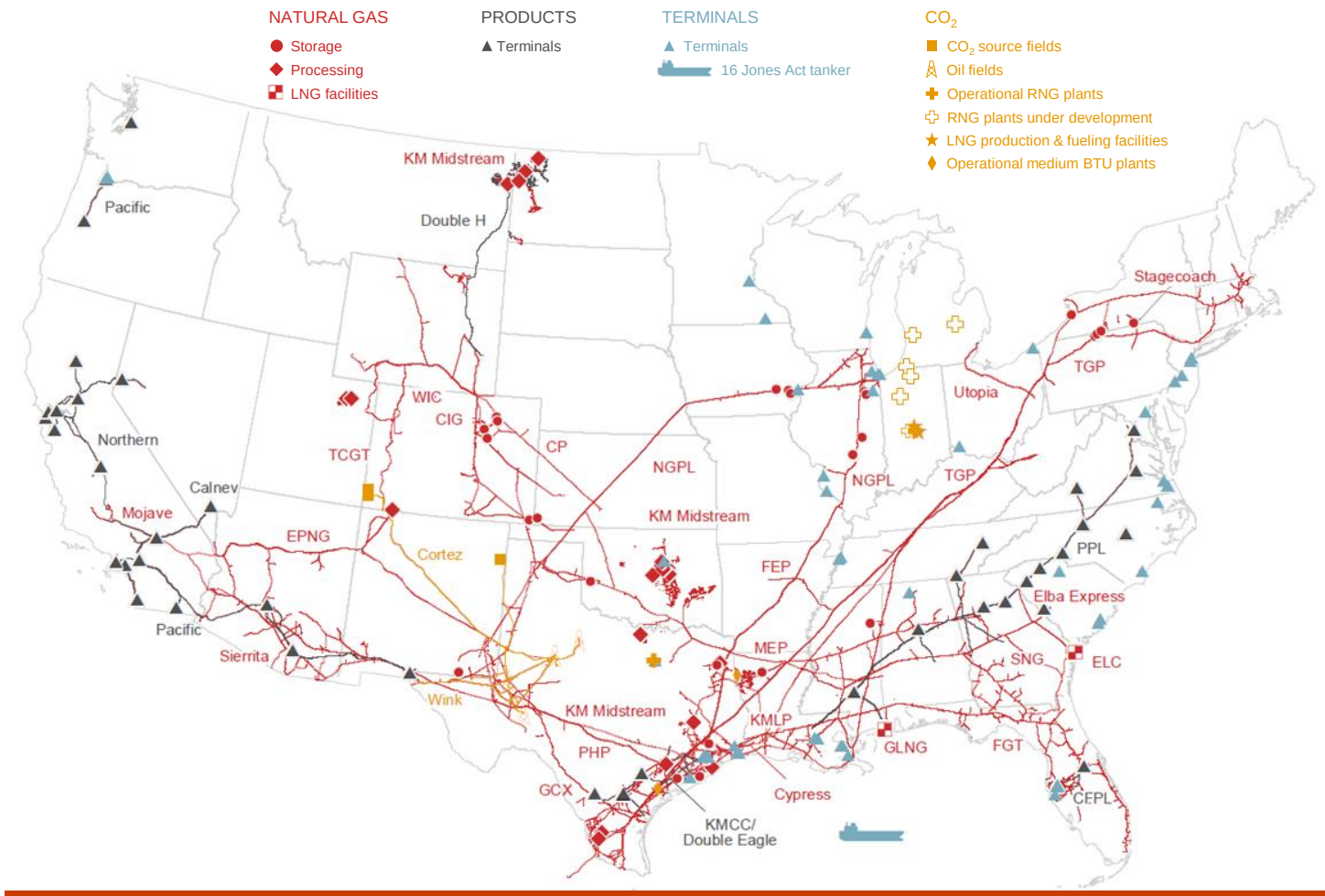
Featured in several ESG indices

FTSE4Good, S&P 500 ESG, JUST Capital

Note: Sustainalytics ESG risk ranking, MSCI ESG rating, FTSE ESG rating rank, Refinitiv ESG score rank, Moody's Vigeo Eiris ESG score, and SSGA R-Factor as of January 2023.

Compelling Investment Opportunity

Strategically-positioned assets generating substantial cash flow with attractive investment opportunities



Largest energy infrastructure company in the S&P500

Stable cash flows with ~67% take-or-pay or hedged earnings[a]

Strong balance sheet with flexibility

Attractive returns on growth projects

~6% current yield & healthy dividend coverage
Top 10 dividend yield in the S&P500

~$2.1 billion of share repurchase program remaining

Highly-aligned management with ~13% share ownership

Positioned for energy future with a vast network of critical assets & low-carbon focus

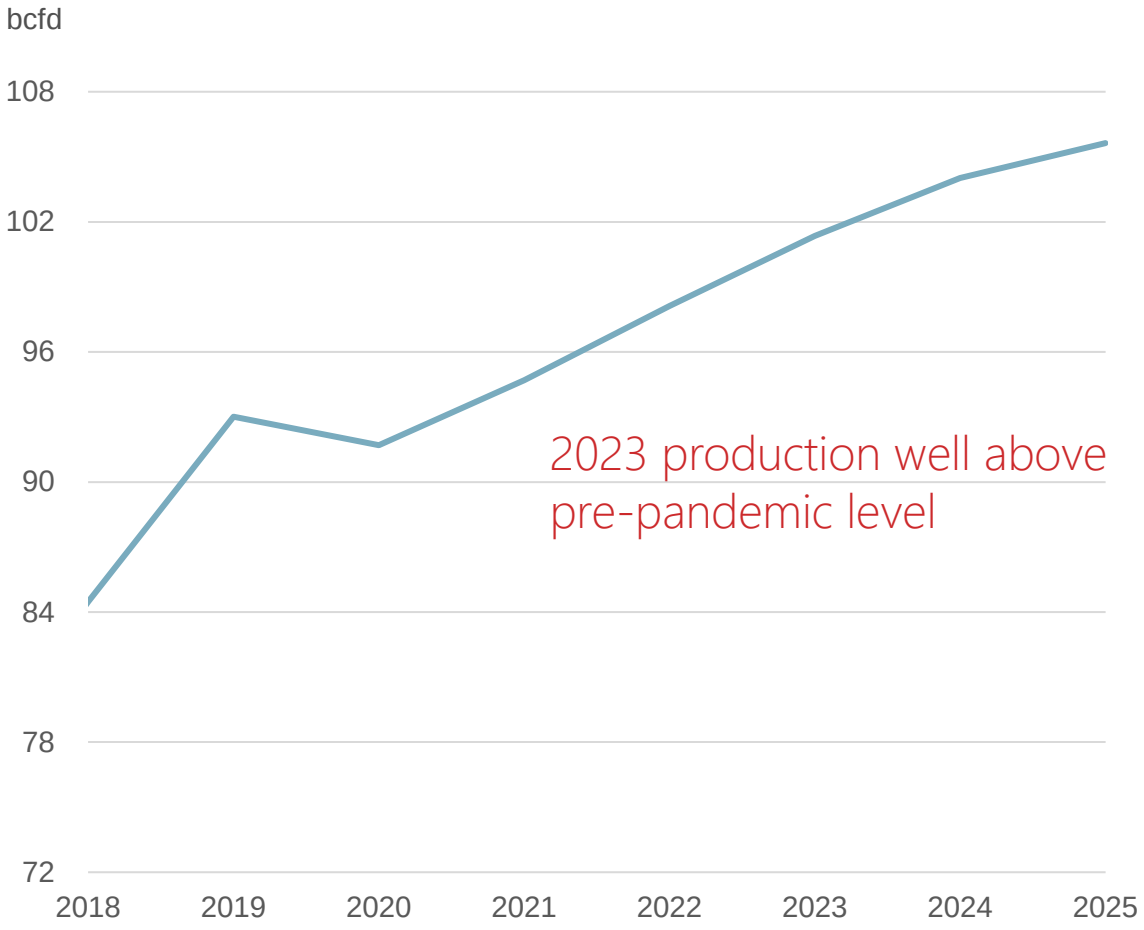
a) Based on Adjusted Segment EBDA (a non-GAAP measure) per 2023 budget. See Non-GAAP Financial Measures & Reconciliations.

APPENDIX

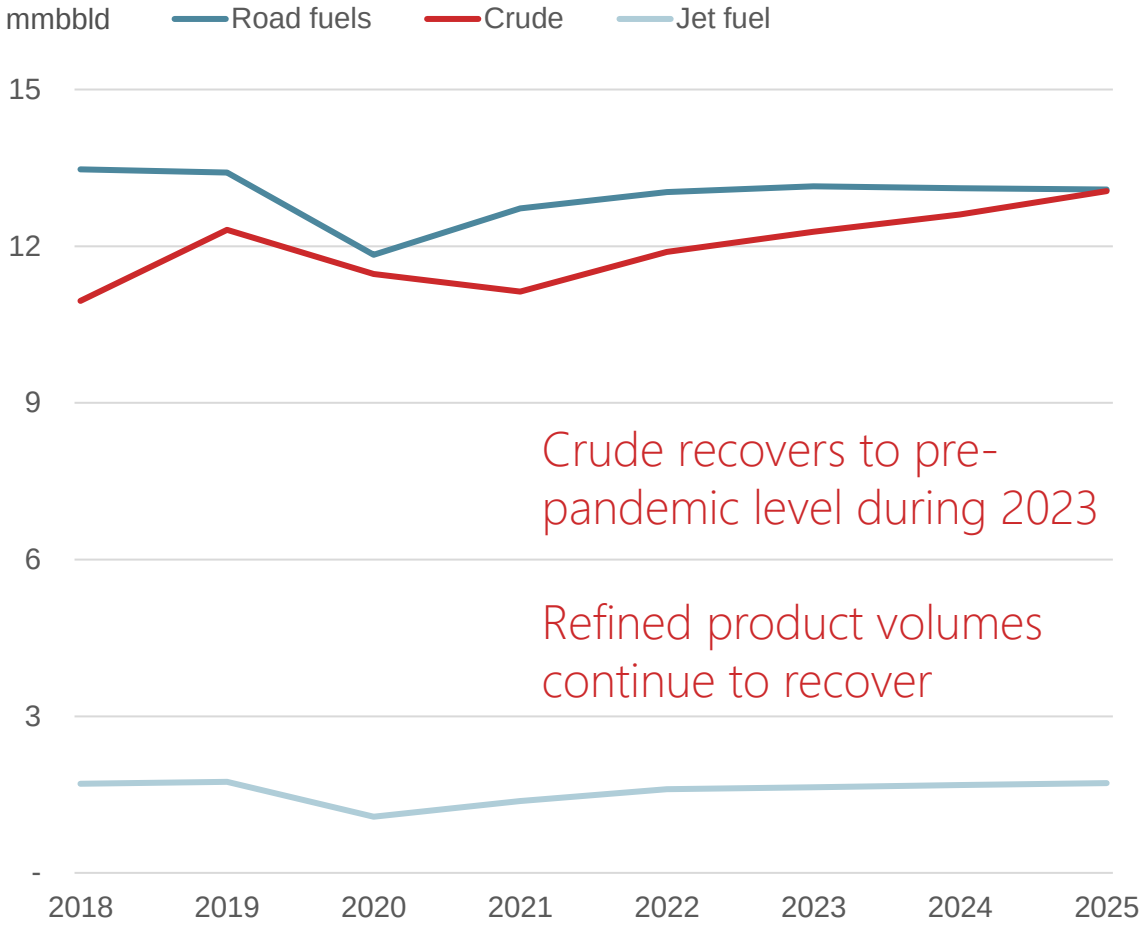
Terminal Pit 11, Pasadena, Texas

U.S. Production Continues to Recover from Pandemic

U.S. NATURAL GAS PRODUCTION



U.S. CRUDE PRODUCTION & REFINED PRODUCT SUPPLY



Left: WoodMackenzie, North America Gas 10-year Investment Horizon Outlook, October 2022.
Right: EIA 2022 Annual Energy Outlook (March 2022).

Natural Gas Gathering & Processing Assets Across Key Basins

Volume recovery ongoing

G&P BUSINESS AS % OF 2023B KMI ADJUSTED SEGMENT EBDA

2% Haynesville

KinderHawk assets with proximity to Gulf Coast industrial & LNG

2% Bakken gas

Hiland system in core Williston acreage, including McKenzie County

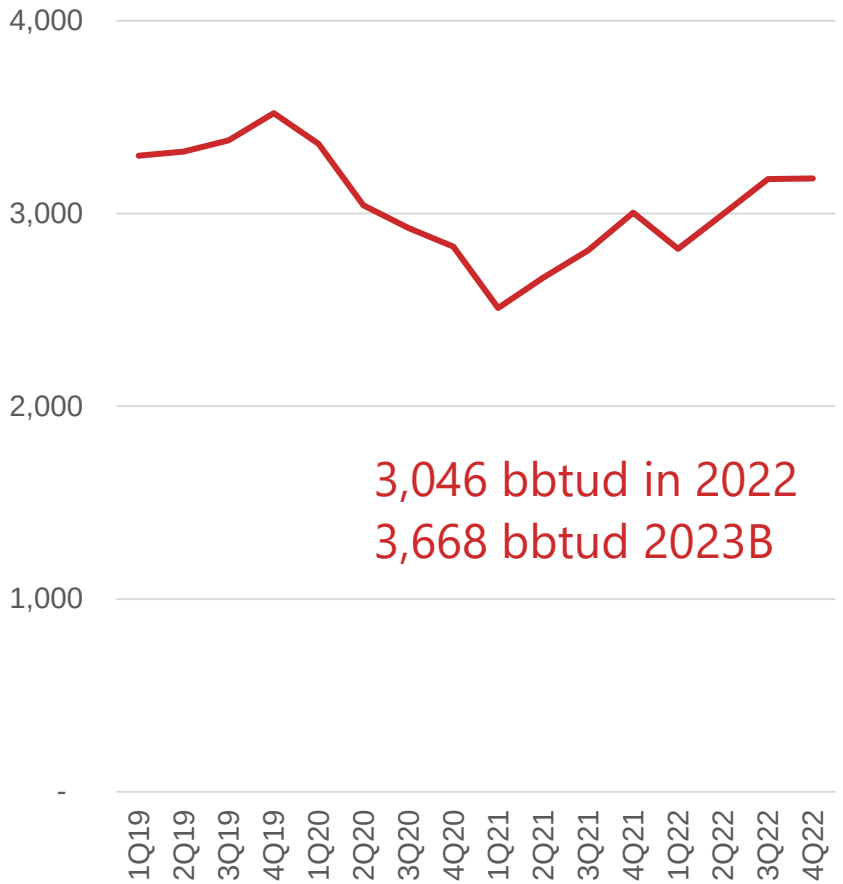
1% Eagle Ford

Copano South Texas & EagleHawk JV assets, primarily in LaSalle County

3% Other gas

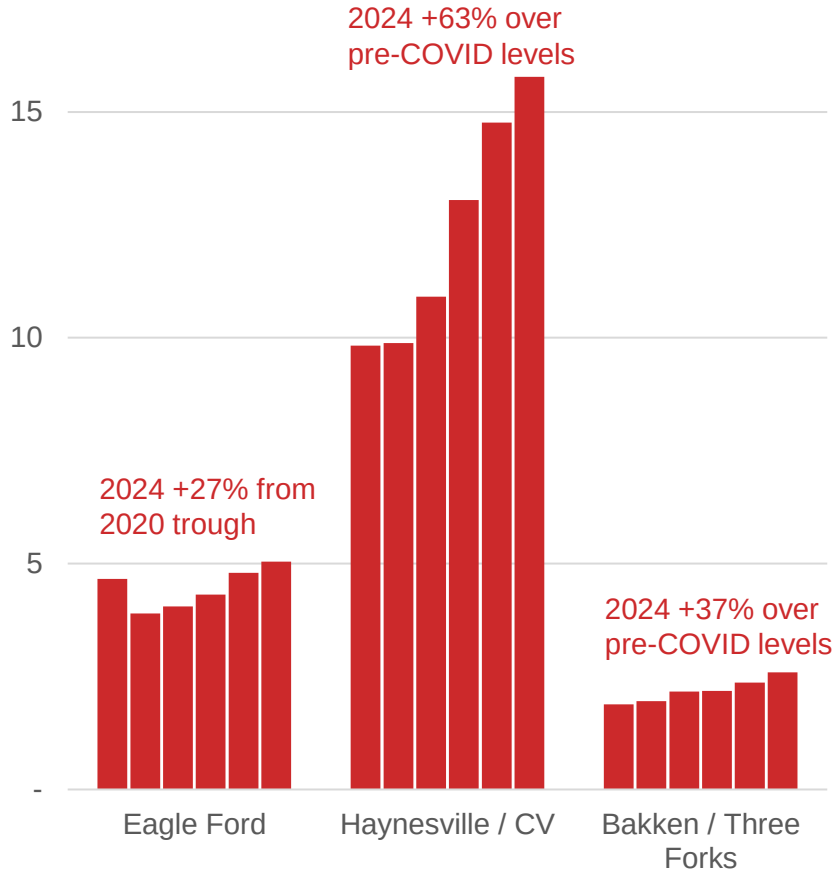
Multiple systems in Uinta, Oklahoma, San Juan & other areas

NATURAL GAS SEGMENT GATHERING VOLUMES bbtud



SHORT-TERM PRODUCTION OUTLOOK

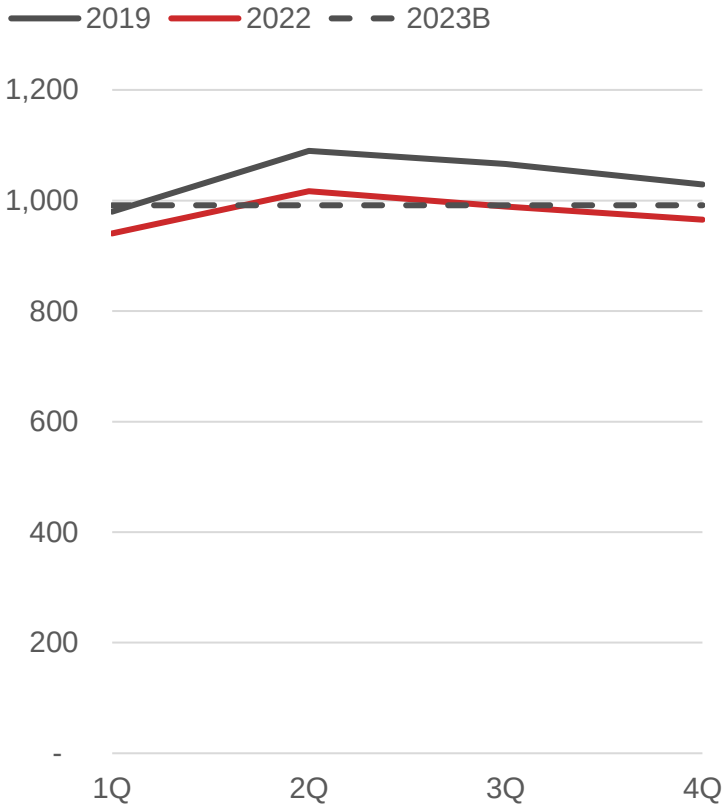
dry gas, bcfd, 2019 – 2024



Note: Adjusted Segment EBDA is a non-GAAP measure. See Non-GAAP Financial Measures & Reconciliations. Pre-COVID levels are based on 2019 production. Production outlook from WoodMackenzie's North America Gas Short-Term Outlook (December 2022).

Refined Products Volumes Recovering to Pre-Pandemic Levels

GASOLINE mbbld



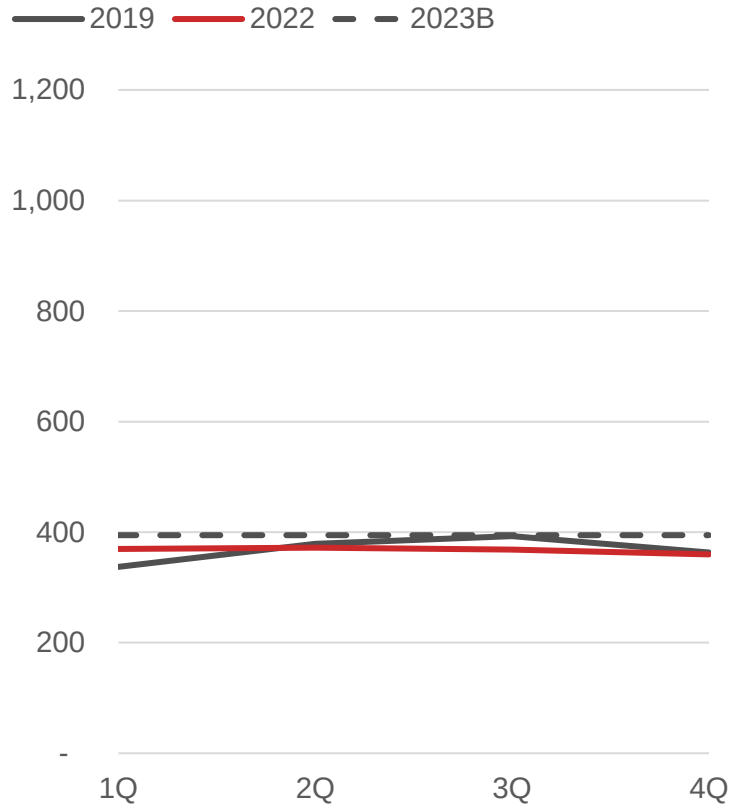
2023B: 992 mbbld

2022: 978 mbbld

2019: 1,041 mbbld

+1% vs 2022

DIESEL mbbld



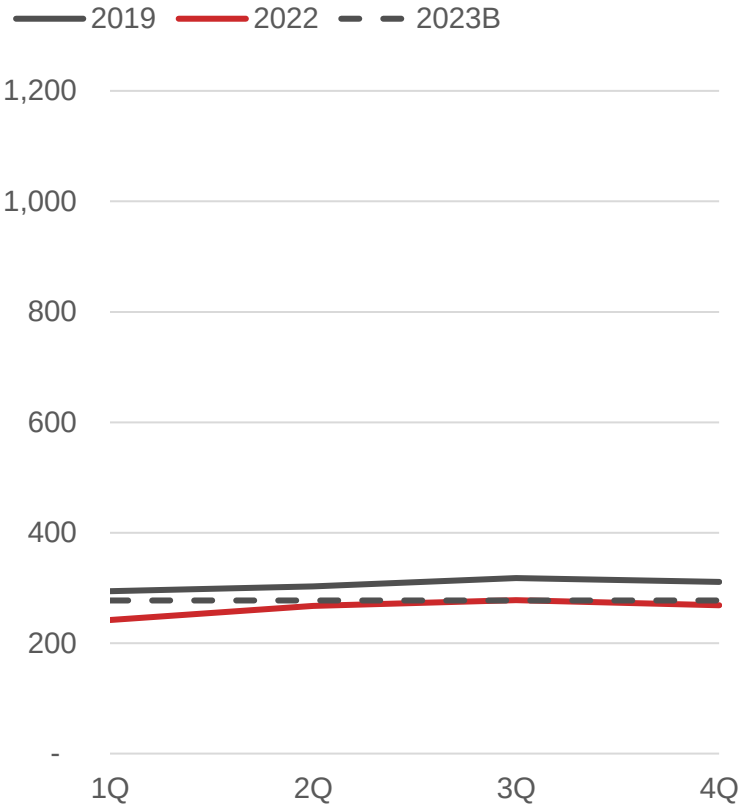
395 mbbld

367 mbbld

368 mbbld

+7% vs 2022

JET FUEL mbbld



277 mbbld

264 mbbld

306 mbbld

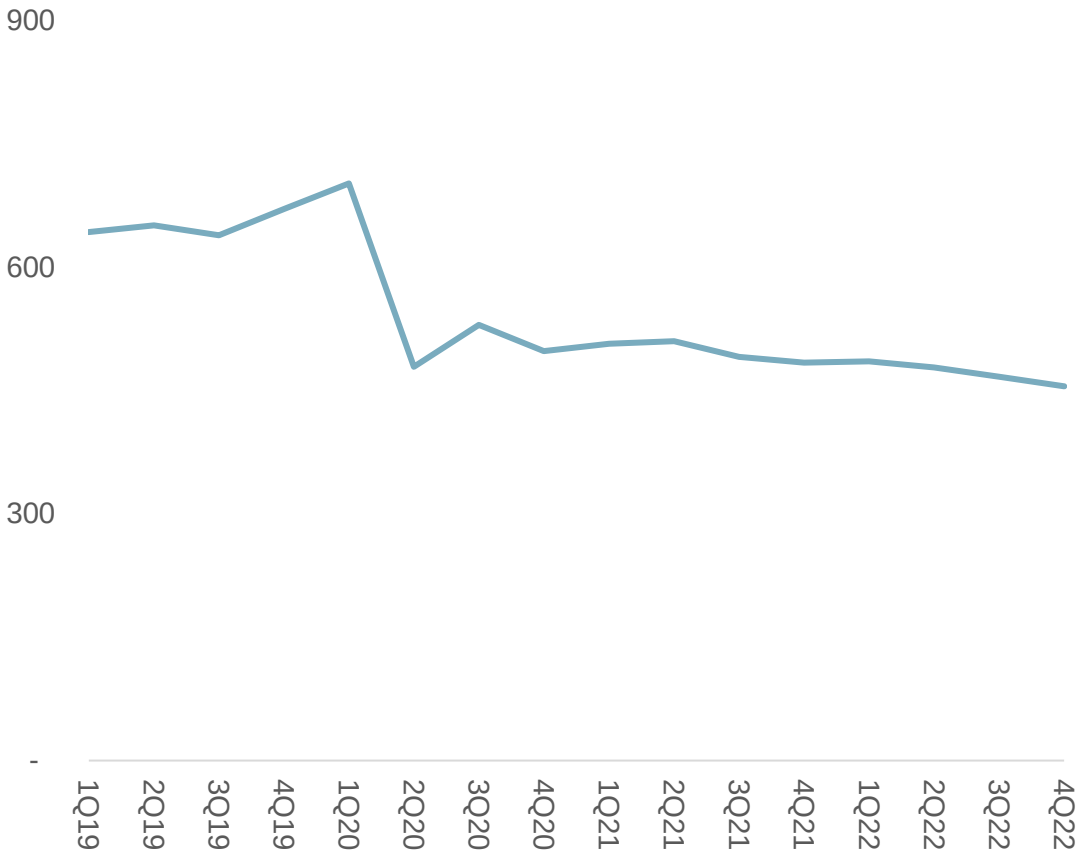
+5% vs 2022

Note: Kinder Morgan Refined Products volumes include SFPP, CALNEV, Central Florida & PPL (KM share).

Products Segment Crude Volume Update

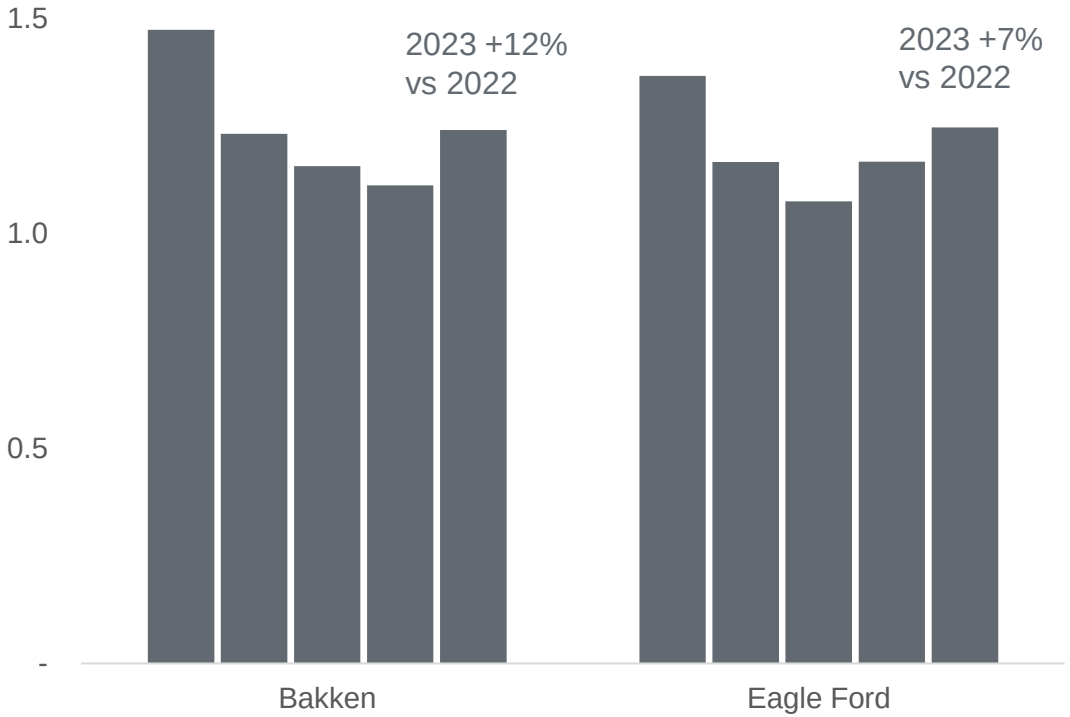
Business as % of 2023B KMI Adjusted Segment EBDA: 1% Crude G&P; 3% Crude Transport

CRUDE TRANSPORT & GATHERING VOLUMES[(a)] mbbld



SHORT-TERM PRODUCTION OUTLOOK 2019 – 2023

crude, mmbld



Crude: 471 mbbld in 2022 | 510 mbbld 2023B

Note: Adjusted Segment EBDA is a non-GAAP measure. See Non-GAAP Financial Measures & Reconciliations. Production outlook from S&P Global Commodity Insights & EIA data.

a) Includes volumes from KMCC, Camino Crude, Double Eagle (KM Share), Double H, and Hiland Crude.

Our Integrated Terminal Network on the Houston Ship Channel

Refined products focused with an irreplaceable collection of assets, capabilities & market-making connectivity

Our unmatched scale & flexibility:

43 million barrels total capacity

31 inbound pipelines

18 outbound pipelines

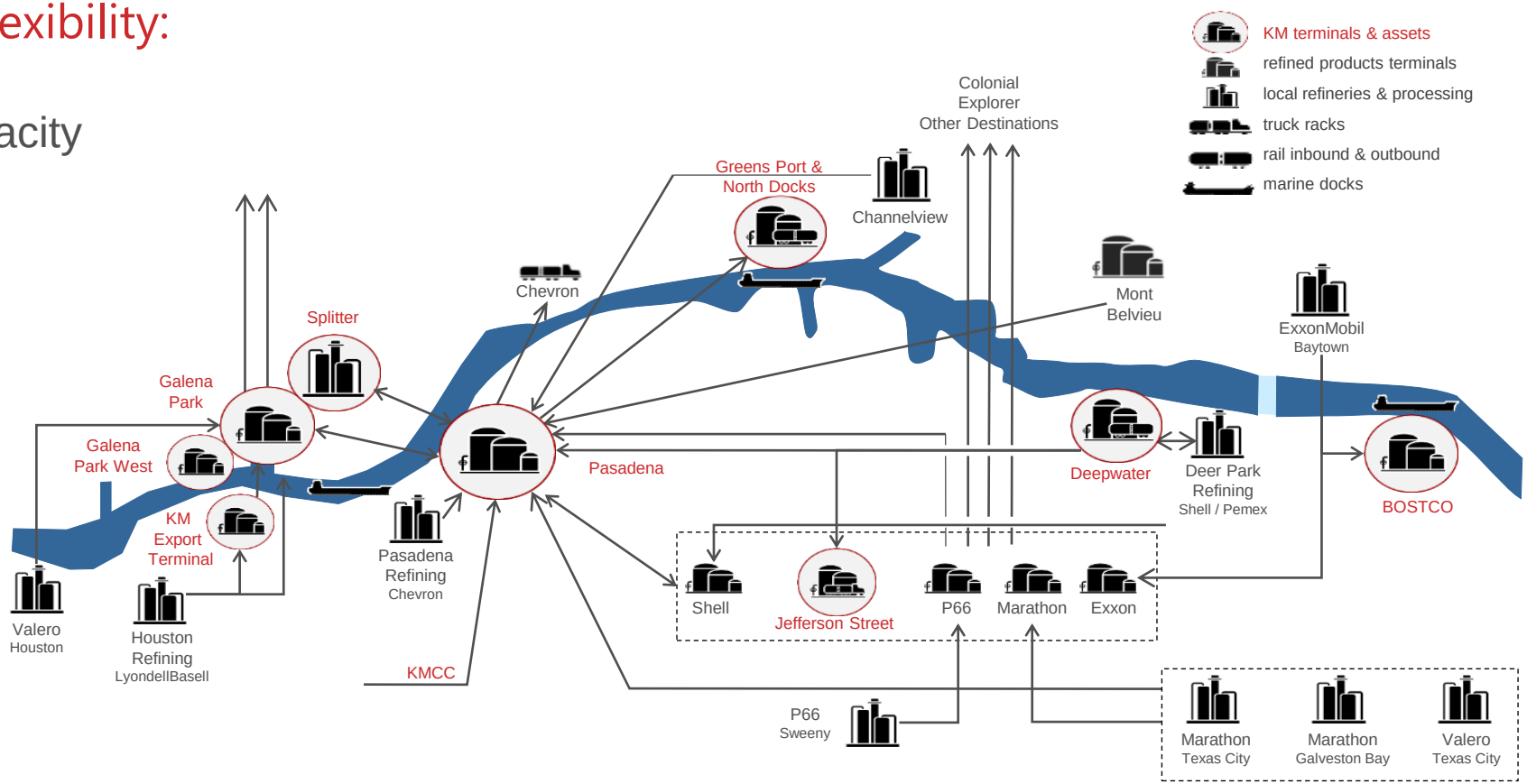
16 cross-channel pipelines

11 ship docks

39 barge spots

35 truck bays

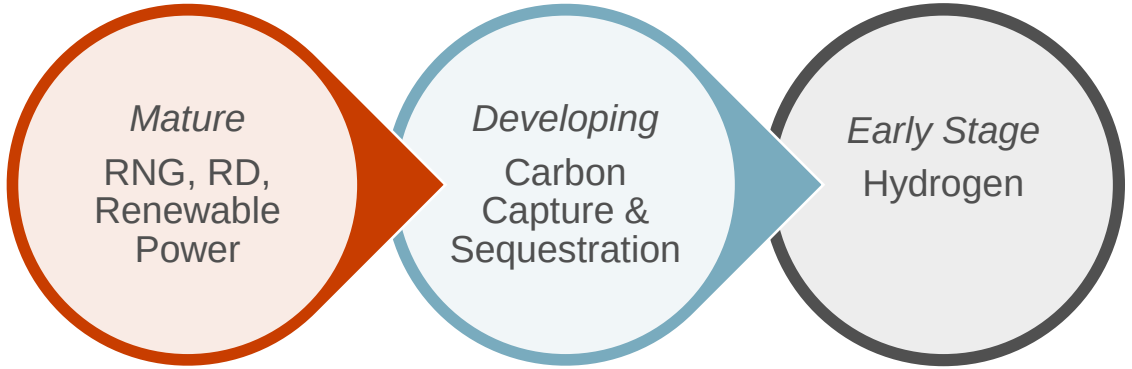
3 unit train facilities



Over $2.2 billion invested since 2010

Energy Transition Ventures (ETV) Group

The group is evaluating commercial opportunities emerging from the low-carbon energy transition



Established a growing RNG platform with the Kinetrex, Mas & NANR acquisitions and expanding opportunities in CCUS space

ETV Group focused on opportunities outside of our existing asset base

Other business segments will continue to pursue their own energy transition opportunities on existing assets

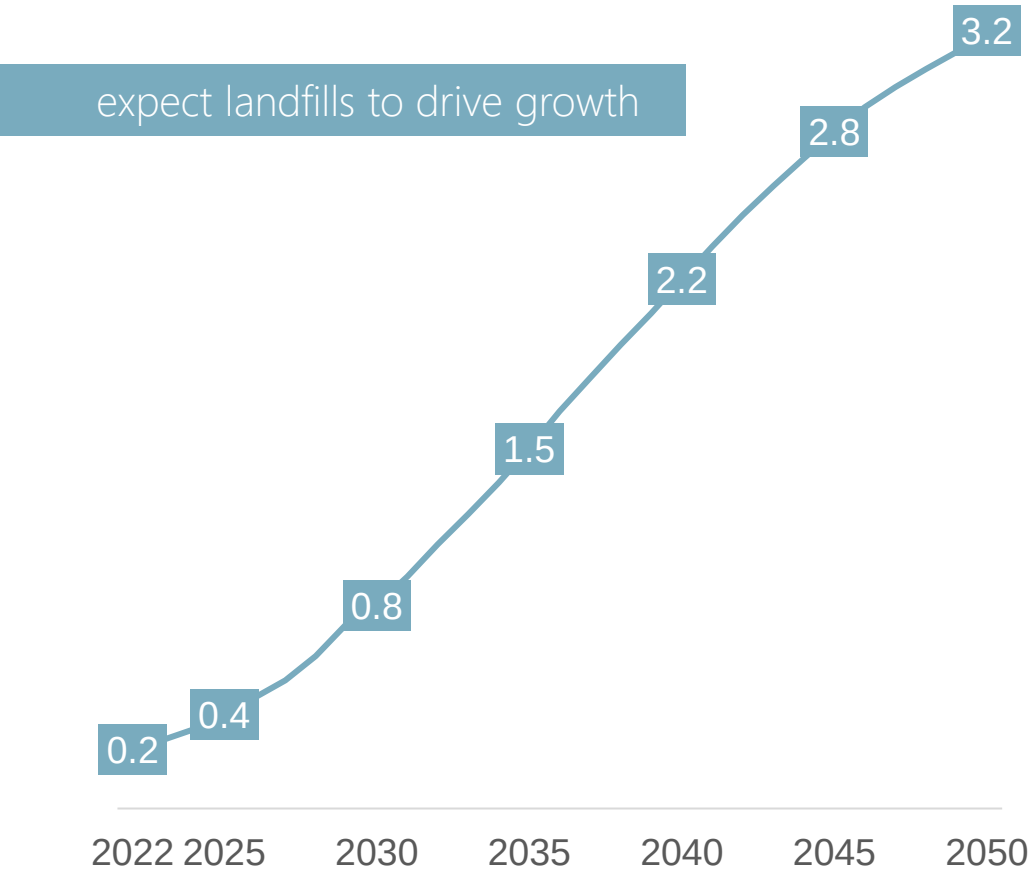
Most attractive opportunities likely to be synergistic with our existing infrastructure and expertise

Projects will have to compete for capital

Remain disciplined and focused on attractive returns exceeding cost of capital

RNG Market Opportunity

U.S. RNG PRODUCTION bcfd



RNG DEMAND MARKETS

transportation market		voluntary market
RNG-based vehicles emit up to 75% less GHG emissions than diesel vehicles[a] Fleets with decarbonization goals may choose to purchase RNG Typically, prices near traditional natural gas price, like Henry Hub for example: **$3.31/MMBtu HH spot price**	If RNG volumes are consumed by fleets in the transportation market, then RIN credits may be earned, which are then purchased by RFS-obligated parties (like refiners) in order to comply with federal requirements: **$26.39/MMBtu D3 RIN value[b]**	Parties interested in voluntarily decarbonizing (like LDCs, utilities, universities, industrial) are increasingly interested in RNG, despite the premium price relative to traditional natural gas
government program incentivizes RNG production, provides margin for producer		slimmer margin but fixed-price, 10+ year contracts

EPA eRIN proposal beginning in 2024 provides additional markets for RNG & landfill gas to electric projects

Sources: U.S. RNG production per WoodMackenzie, North America Gas 10-year Investment Horizon Outlook, October 2022. Includes all forms of RNG production.

a) Emissions data per the EPA.

b) $2.25 2023 D3 RIN price (per Argus) multiplied by 11.727 to convert to $/MMBtu. Pricing as of 1/18/2023.

Contract Strategy Insulates Cash Flow Through Commodity Cycles

Structure long-term contracts that minimize price & volume volatility

	2023B Adjusted Segment EBDA:	67% take-or-pay or hedged Volumes & price are contractually fixed	26% fee-based Price is fixed, volumes are variable	7% Commodity-price based	Avg. remaining contract life as of 1/1/2023	Additional cash flow security
Natural Gas	Interstate / LNG	40%	3%		6.0 / 17.7 years	Tariffs are FERC-regulated
	TX Intrastate	9%	2%		6.2 years	
	G&P	1%	6%	2%	4.1 years	Primarily acreage dedications for fee-based contracts
Products	Refined products	1%	9%	1%	generally not applicable	Pipeline tariffs are FERC-regulated ~2/3 of 2023B Products Segment Adj. Segment EBDA has an annual inflation-linked tariff escalator
	Crude transport	2%	1%		2.3 years	
	Crude G&P		1%			
Terminals	Liquids terminals	5%	2%		2.7 years	~3/4 of 2023B Terminals Segment Adj. Segment EBDA has annual price escalators (inflation linked or fixed price escalators) Bulk terminals: primarily minimum volume guarantee or requirements
	Jones Act tankers	2%			3.3 years	
	Bulk terminals	1%	2%		4.3 years	
CO_2	EOR Oil & Gas	5%		2%		
	CO_2 & Transport	1%		1%	6.2 years	Commodity-price based contracts are mostly minimum volume committed
	ETV			1%		

Note: Adjusted Segment EBDA is a non-GAAP measure. See Non-GAAP Financial Measures & Reconciliations. Numbers may not sum due to rounding. TX Intrastate average remaining contract life includes term sale portfolio.

2023 Budget Sensitivities

Limited overall commodity exposure

2023B assumptions	Change	Potential Impact to Adjusted EBITDA & DCF (full year)				
		Natural Gas	Products	Terminals	CO_2	Total
Natural gas G&P volumes 3,668 bbtud	+/- 5%	$40 million				$40 million
Refined products volumes (gasoline, diesel & jet fuel) 1,663 mbbld for Products segment	+/- 5%		$37 million	$12 million		$49 million
Crude oil & condensate volumes (includes Bakken oil G&P) 510 mbbld net	+/- 5%		$15 million			$15 million
Crude oil & NGL production volumes 38 mbbld net	+/- 5% in net volumes				$25 million	$25 million
$85.00/bbl WTI crude oil price	+/- $1/bbl WTI	$1.0 million	$1.2 million		$3.6 million	$5.8 million
$5.50/Dth natural gas price	+/- $0.10/Dth	$1.0 million[(a)]				$1.0 million[(a)]
NGL / crude oil price ratio 54% in Natural Gas segment & 45% in CO_2 segment	+/- 1% price ratio	$1.4 million			$3.5 million	$4.9 million
$2.71/RIN D3 RIN price	+/- $0.10/RIN				$3.8 million	$3.8 million
		Potential Impact to DCF (balance of year)				
SOFR rate: 4.72%	+/-10-bp change in SOFR					$6.3 million[(b)]

Note: These sensitivities are general estimates of anticipated impacts on our business segments & overall business of changes relative to our assumptions; the impact of actual changes may vary significantly depending on the affected asset, product & contract. Adjusted EBITDA and Distributable Cash Flow (DCF) are non-GAAP measures. See Non-GAAP Financial Measures & Reconciliations at the end of this presentation for additional information.

a) Assumes constant ethane frac spread vs. natural gas prices.

b) As of 12/31/2022, we had ~$7.5 billion of fixed-to-floating interest rate swaps on our long-term debt and ~24% of the principal amount of our debt balance was subject to variable interest rates – either as short- or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swaps. Taking into account SOFR locks effective on 12/30/2022 (and not included in budget), we have fixed the LIBOR component on $1.25 billion of our floating rate swaps through the end of 2023, and effectively 20% of our debt therefore subject to variable interest rates.

Minimum Book Tax Detail

High-level example of calculation
Net income
Add back: Book depreciation
Add back: Book federal income tax
Subtract: Tax depreciation
Adjusted Financial Statement Income (AFSI)
x 15%
Minimum Book Tax (MBT)
Subtract: Any applicable credits
MBT after credits

Pay the greater: MBT or ordinary federal cash taxes

Limited to 75% of MBT annually; $298 million of General Business Credits as of 12/31/22

- MBT applies to companies generating average annual AFSI >$1bn over the prior 3 years
- Do not expect to be subject to MBT in 2023, 2024, or 2025
- 100% of MBT payments can be credited against future ordinary tax

ESG Strategy

Provide energy transportation & storage services in a safe, efficient, and environmentally responsible manner for the benefit of people, communities, and businesses

Environmental

Invest in low carbon future

- Grow natural gas transmission, RSG, RNG, and LNG businesses
- Invest in renewable fuel midstream assets
- Evaluate CCUS & hydrogen opportunities
- Energy transition ventures group explores opportunities beyond our core business

Work to minimize environmental impact from our operations

- Work to reduce emissions
- Restore & protect biodiversity

Social

Safety-focused culture

Build & maintain relationships with stakeholders where we operate

Foster a diverse, inclusive, and respectful workplace

Support employee career development

Expect employees & representatives to adhere to our Code of Business Conduct and Ethics and Supplier Code of Conduct

Governance

Risks & opportunities are monitored and communicated to leadership

Board evaluates long-term business strategy for resilience & adaptability

Board committees include EHS (including ESG), Audit, Compensation, and Nominating & Governance

Operations Management System establishes routine risk management activities

Supporting a Low Carbon Future & Enabling Our Customers to Meet Their GHG Goals

Methane emission reductions & transparent disclosure

- Annual or more frequent compressor station leak surveys on natural gas transmission & storage and target for gathering & boosting assets
- Founding member of ONE Future; natural gas T&S methane intensity of 0.03% vs. 0.31% target
- Avoided 133 bcf of methane emissions or 71mm MT of CO_2e since 1993 (6.65 bcf/year)
- Avoided 276,000 metric tons of CO_2e in 2021 from use of DRA
- TCFD aligned disclosure including limited assurance of Scope 1, Scope 2, & GHG Intensity

Economic opportunities to participate in energy transition

- ~80% of 2023B discretionary capital allocated towards lower carbon fuels
- Installing vapor recovery units in Houston Ship Channel – 38% GHG reduction from 2019
- Existing RNG development portfolio of up to ~7.4 bcf per year of gross production capacity
- 10 existing RNG pipeline interconnects with total capacity of 36 mmcfd.
  3 additional RNG interconnects under construction with capacity of 9 mmcfd
- Leveraging CO_2 experience to participate in developing CCUS market

R&D for new technologies

- Cheniere-led QMRV project - quantifying, monitoring, reporting, & verifying GHG emissions
- New York State's Emission Measurement Project – methane monitoring and measurement technology testing
- Methane Emissions Technology Evaluation Center Advisory Board Membership
- Understanding the effects of blending & transporting hydrogen through our existing pipeline infrastructure
- Research on storing hydrogen in repurposed underground natural gas storage facilities

Note: Lower carbon fuels include conventional natural gas, responsibly sourced natural gas, RNG, LNG, renewable diesel, other biofuels, biofuel feedstocks, and CCS.

Infrastructure is Essential to Reduce & Avoid GHG Emissions

ONGOING ACTIVITES

Avoided or reduced 17.1mm metric tons CO_2e in 2021

2021 Activities	CO_2e avoided/reduced (metric tons)
Ethanol[(a)]	10,900,000
Voluntary methane reductions – Methane Challenge[(b)]	3,600,000
Biodiesel[(c)]	1,350,000
Renewable diesel[(c)]	622,000
RNG interconnects	307,000
DRA use on Products Pipelines	276,000
Solar panels	749

Note: Blue highlighted activities and projects directly reduce or avoid KM Scope 1 or 2 GHG emissions. All other activities reduce third-party emissions.

a) Assumes a 20% reduction in life cycle emissions compared to gasoline, per the Renewable Fuel Standard (RFS) requirement for renewable fuels life cycle reduction.
b) Voluntary methane emission reductions include reductions from compressor station leak repairs, pipeline pumpdowns, gas turbine installations, electric motor installations, and alternative pipeline maintenance technologies that reduce the need for pipeline blowdowns.
c) Assumes a 50% reduction in life cycle emissions compared to diesel, per the RFS requirement for biodiesel fuels life cycle reduction.
d) Includes 1,300,000 MT CO_2e attributable to in-service RNG facilities (Indy HBTU and Arlington).
e) Expect majority of Southern CA and Northern CA renewable fuels projects in-service during 1Q 2023.

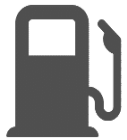
ANNOUNCED PROJECTS

Potential to avoid or reduce 9.8mm metric tons CO_2e annually

Projects	Annual CO_2e avoided/reduced (metric tons)	In-service date
RNG production[(d)]	4,200,000	2023 – 2024
Renewable feedstock hubs[(c)]	2,300,000	Q1’23/Q4’24
California renewable diesel[(c)]	2,000,000	Q1’23[(e)]
RNG interconnects	865,000	varies
CCS Red Cedar	400,000	Q2’24
VRU’s Houston Ship Channel	34,000	Q3’23

Total CO_2e emissions avoided/reduced from ongoing & announced projects : 26.9mm metric tons per year, equivalent to:

62mm barrels of oil consumed



3,022mm gallons of gasoline consumed

carbon sequestered by 32mm acres of U.S. forest

NON-GAAP FINANCIAL MEASURES & RECONCILIATIONS

Elba liquefaction, Elba Island, Georgia

Use of Non-GAAP Financial Measures

The non-GAAP financial measures of Adjusted Earnings and distributable cash flow (DCF), both in the aggregate and per share for each; segment earnings before depreciation, depletion, amortization (DD&A), amortization of excess cost of equity investments and Certain Items (Adjusted Segment EBDA); net income before interest expense, income taxes, DD&A, amortization of excess cost of equity investments and Certain Items (Adjusted EBITDA); Net Debt; Net Debt-to-Adjusted EBITDA; Project EBITDA; Free Cash Flow (or FCF); and CO_2 EOR & Transport FCF are presented herein.

Our non-GAAP financial measures described further 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 these non-GAAP financial measures by reviewing our comparable GAAP measures, understanding the differences between the measures and taking this information into account in its analysis and its decision-making processes.

We do not provide (i) budgeted revenue (the GAAP financial measure closest to net revenue) due to impracticality of predicting certain items required by GAAP, including projected commodity prices at the multiple purchase and sale points across certain intrastate pipeline systems. Instead, we are able to project the net revenue received for transportation services based on contractual agreements and historical operational experience; (ii) budgeted CO_2 EOR & Transport Segment EBDA (the GAAP financial measure most directly comparable to 2023 budgeted CO_2 EOR & Transport 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 on derivatives marked to market; or (iii) 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.

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 our view 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 from Joint Ventures” below).

Adjusted Earnings is calculated by adjusting net income attributable to Kinder Morgan, Inc. for Certain Items. Adjusted Earnings is used by us and certain external users of our financial statements to assess the earnings of our business excluding Certain Items as another reflection of our ability to generate earnings. We believe the GAAP measure most directly comparable to Adjusted Earnings is net income attributable to Kinder Morgan, Inc. Adjusted Earnings per share uses Adjusted Earnings and applies the same two-class method used in arriving at basic earnings per share.

Distributable Cash Flow is calculated by adjusting net income attributable to Kinder Morgan, Inc. for Certain Items (or Adjusted Earnings, as defined above), and further by DD&A and amortization of excess cost of equity investments, income tax expense, cash taxes, sustaining capital expenditures and other items. We also include amounts from joint ventures for income taxes, DD&A and sustaining capital expenditures (see “Amounts from Joint Ventures” below). DCF is a significant performance measure useful to management and external users of our financial statements in evaluating our performance and in measuring and estimating the ability of our assets to generate cash earnings after servicing our debt, paying cash taxes and expending sustaining capital, that could be used for discretionary purposes such as dividends, stock repurchases, retirement of debt, or expansion capital expenditures. 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.

Use of Non-GAAP Financial Measures (Continued)

Adjusted Segment EBDA is calculated by adjusting segment earnings before DD&A and amortization of excess cost of equity investments (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. General and administrative expenses and certain corporate charges are generally not under the control of our segment operating managers, and therefore, are not included when we measure business segment operating performance. We believe Adjusted Segment EBDA is a useful performance metric because it provides management and external users of our financial statements additional insight into the ability of our segments to generate cash earnings on an ongoing basis. 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.

Adjusted EBITDA is calculated by adjusting net income attributable to Kinder Morgan, Inc. before interest expense, income taxes, DD&A, and amortization of excess cost of equity investments (EBITDA) for Certain Items. We also include amounts from joint ventures for income taxes and DD&A (see "Amounts from Joint Ventures" below). Adjusted EBITDA is used by management and external users, in conjunction with our Net Debt (as described further below), to evaluate our leverage. Therefore, we believe Adjusted EBITDA is useful to investors. We believe the GAAP measure most directly comparable to Adjusted EBITDA is net income attributable to Kinder Morgan, Inc.

Amounts from 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 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. 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. Adjusted EBITDA are further adjusted for certain KML activities attributable to our NCI in KML for the periods presented through KML's sale on December 16, 2019.

Net Debt is calculated by subtracting from total debt (i) cash and cash equivalents, (ii) debt fair value adjustments, and (iii) the foreign exchange impact on Euro-denominated bonds for which we have entered into currency swaps. Net Debt, on its own and as part of a ratio of Net Debt-to-Adjusted EBITDA, is a non-GAAP financial measure that management believes is useful to investors and other users of our financial information in evaluating our leverage. We believe the most comparable measure to Net Debt is total debt.

Net revenue means aggregate budgeted revenue which includes, where applicable, revenue minus cost of goods sold. Management uses net revenue to track customer types and customer credit ratings in our contract portfolio.

Project EBITDA 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 from Joint Ventures." Management uses 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.

Free Cash Flow or FCF is calculated by reducing cash flow from operations for capital expenditures (sustaining and expansion). FCF is used by external users as an additional leverage metric. Therefore, we believe FCF is useful to our investors. We believe the GAAP measure most directly comparable to FCF is cash flow from operations.

CO_2 EOR & Transport Free Cash Flow is calculated by reducing EBDA (GAAP) for our CO_2 EOR & Transport assets by Certain Items, capital expenditures (sustaining and expansion) and acquisitions attributable to the EOR & Transport assets. Management uses CO_2 EOR & Transport Free Cash Flow as an additional performance measure for our CO_2 EOR & Transport assets. We believe the GAAP measure most directly comparable to CO_2 EOR & Transport Free Cash Flow is EBDA (GAAP) for our CO_2 EOR & Transport assets.

GAAP Reconciliations

$ in millions

	2022			2023 Budget		
Reconciliation of Adjusted Segment EBDA	Segment EBDA (GAAP)	Items in Adjusted Segment EBDA	Adjusted Segment EBDA	Segment EBDA (GAAP)	Items in Adjusted Segment EBDA	Adjusted Segment EBDA
Natural Gas Pipelines	$4,801	$141	$4,942	$5,066	-	$5,066
Products Pipelines	1,107	-	1,107	1,238	-	1,238
Terminals	975	-	975	1,000	-	1,000
CO_2	819	(11)	808	879	-	879
Total	$7,702	$130	$7,832	$8,183	-	$8,183

Certain Items	2022
Fair value amortization	$ (15)
Legal, environmental and other reserves	51
Change in fair value of derivative contracts[(a)]	57
Income tax Certain Items	(37)
Other	32
Total Certain Items	$ 88

Reconciliation of Net Debt	2022
Current portion of debt (GAAP)	$ 3,385
Total long-term debt (GAAP)	28,403
Debt fair value adjustments	(115)
Foreign exchange impact on hedges for Euro Debt outstanding	8
Less: cash & cash equivalents	(745)
Net Debt	$ 30,936
Adjusted EBITDA	$ 7,516
Net Debt to Adjusted EBITDA	**4.1X**

a) Gains or losses are reflected in our DCF when realized.

GAAP Reconciliations

$ in millions

Reconciliation of DD&A and amortization of excess cost of equity investments for DCF		2022
Depreciation, depletion and amortization (GAAP)	$	(2,186)
Amortization of excess cost of equity investments (GAAP)		(75)
DD&A and amortization of excess cost of equity investments		(2,261)
JV DD&A		(273)
DD&A and amortization of excess cost of equity investments for DCF	$	(2,534)

Reconciliation of general and administrative and corporate charges		
General and administrative (GAAP)	$	(637)
Corporate benefit		44
Certain Items		6
General and administrative and corporate charges[(a)]	$	(587)

Reconciliation of interest, net		
Interest, net (GAAP)	$	(1,513)
Certain Items		(11)
Interest, net[(a)]	$	(1,524)

Reconciliation of income tax expense for DCF		2022
Income tax expense (GAAP)	$	(710)
Certain Items		(37)
Income tax expense[(a)]		(747)
Unconsolidated JV income tax expense[(a,b)]		(75)
Income tax expense for DCF[(a)]	$	(822)

Reconciliation of additional JV information		
Unconsolidated JV DD&A	$	(323)
Less: Consolidated JV partners' DD&A		(50)
JV DD&A		(273)
Unconsolidated JV income tax expense[(a,b)]		(75)
JV DD&A and income tax expense[(a)]	$	(348)
Unconsolidated JV cash taxes[(b)]	$	(70)
Unconsolidated JV sustaining capital expenditures	$	(148)
Less: Consolidated JV partners' sustaining capital expenditures		(8)
JV sustaining capital expenditures	$	(140)

a) Amounts are adjusted for Certain Items.
b) Amounts are associated with our Citrus, NGPL and Products (SE) Pipeline equity investments.

Net Income & Adjusted EBITDA

$ in millions

	2023 Budget	2022 Actual	Change $	Change %
Net income attributable to Kinder Morgan, Inc. (GAAP)	**$ 2,525**	**$ 2,548**	**$ (23)**	**-1%**
Total Certain Items	(12)	88	(100)	NM
DD&A and amortization of excess cost of equity investments	2,264	2,261	3	0%
Income tax expense[(a)]	724	747	(23)	(3%)
JV DD&A and income tax expense[(a,b)]	345	348	(3)	(1%)
Interest, net[(a)]	1,855	1,524	331	22%
Adjusted EBITDA	**$ 7,701**	**$ 7,516**	**$ 185**	**2%**

Note: See Non-GAAP Financial Measures and Reconciliations.
a) Amounts are adjusted for Certain Items.
b) Represents JV DD&A and income tax expense.

Reconciliations of KMI FCF & CO_2 Segment FCF

$ in millions

Reconciliation of KMI FCF	2018	2019	2020	2021	2022
CFFO (GAAP)	**$ 5,043**	**$ 4,748**	**$ 4,550**	**$ 5,708**	**$ 4,967**
Capital expenditures (GAAP)[(a)]	(2,904)	(2,270)	(1,707)	(1,281)	(1,621)
FCF	**2,139**	**2,478**	**2,843**	**4,427**	**3,346**
Dividends paid (GAAP)[(b)]	(1,774)	(2,163)	(2,362)	(2,443)	(2,504)
FCF after dividends	**$ 365**	**$ 315**	**$ 481**	**$ 1,984**	**$ 842**

Reconciliation of CO_2 EOR & Transport FCF					
EBDA for CO_2 EOR & Transport (GAAP)	$ 759	$ 681	$ (292)	$ 752	$ 800
Certain items:					
Loss (gain) on non-cash impairments, project write-offs and divestitures	79	75	950	(10)	-
Derivatives and other	90	(49)	(6)	4	(11)
Severance tax refund	(21)	-	-		-
Adjusted EBDA for CO_2 EOR & Transport	**907**	**707**	**652**	**746**	**789**
Capital expenditures (GAAP)[(a)]	(397)	(349)	(186)	(185)	(275)
Acquisitions	(21)	-	-		
CO_2 EOR & Transport FCF	**$ 489**	**$ 358**	**$ 466**	**$ 561**	**$ 514**

a) Includes sustaining and expansion capital expenditures.
b) 2018 includes dividends paid for the preferred shares.

Reconciliation of Adjusted EBITDA, Normalized for Divestitures

$ in millions

Reconciliation of Adjusted EBITDA, Normalized for Divestitures	2016	2017	2018	2019	2020	2021	2022
Net income attributable to Kinder Morgan, Inc. (GAAP)	**$ 708**	**$ 183**	**$ 1,609**	**$ 2,190**	**$ 119**	**$ 1,784**	**$ 2,548**
Noncontrolling interest certain item	(8)	-	-	-	-	-	-
KML noncontrolling interests[(a)]	-	28	58	33	-	-	-
Total Certain Items	933	1,445	501	(29)	1,892	1,220	88
DD&A and amortization of excess cost of equity investments	2,268	2,322	2,392	2,494	2,304	2,213	2,261
Income tax expense[(a)]	899	853	645	627	588	860	747
JV DD&A and income tax expense[(a,b)]	443	496	472	487	449	351	348
Interest, net[(a)]	1,999	1,871	1,891	1,816	1,610	1,518	1,524
Adjusted EBITDA	**$ 7,242**	**$ 7,198**	**$ 7,568**	**$ 7,618**	**$ 6,962**	**$ 7,946**	**$ 7,516**
Divested adjusted EBITDA[(a)]	(701)	(534)	(526)	(399)	(94)	(56)	(48)
As normalized for divestitures	**$ 6,541**	**$ 6,664**	**$ 7,042**	**$ 7,219**	**$ 6,868**	**$ 7,890**	**$ 7,468**

Note: See Non-GAAP Financial Measures and Reconciliations.
a) Amounts are adjusted for Certain Items.
b) Represents JV DD&A and income tax expense.