

# 2024 INVESTOR DAY

January 24, 2024

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

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**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”).

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**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.

# Kinder Morgan 2024 Investor Day Agenda & Presenters



**Investor Perspective**  
Rich Kinder, Executive Chairman  
9:00 – 9:10



**Outlook**  
Kimberly Dang, CEO  
9:10 – 9:30



**Fireside Chat with Natural Gas President**  
Sital K. Mody, Natural Gas  
9:30 – 10:00



**Strategy & Execution**  
Tom Martin, President  
10:00 – 10:20

**Business Unit Panel with Products, Terminals, and CO<sub>2</sub> & ETV Presidents**  
10:35 – 11:05



Dax Sanders  
Products



John Schlosser  
Terminals



Anthony Ashley  
CO<sub>2</sub> & ETV Group



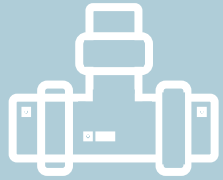
**Financial Overview**  
David Michels, CFO  
11:05 – 11:25

**Corporate Q&A**  
11:25 – 12:00



# INVESTOR PERSPECTIVE

*Rich Kinder*



## LEADER IN U.S. ENERGY INFRASTRUCTURE

*Economic moat of highly contracted, irreplaceable assets*



## GROWING, NATURAL GAS FOCUSED CASH FLOWS

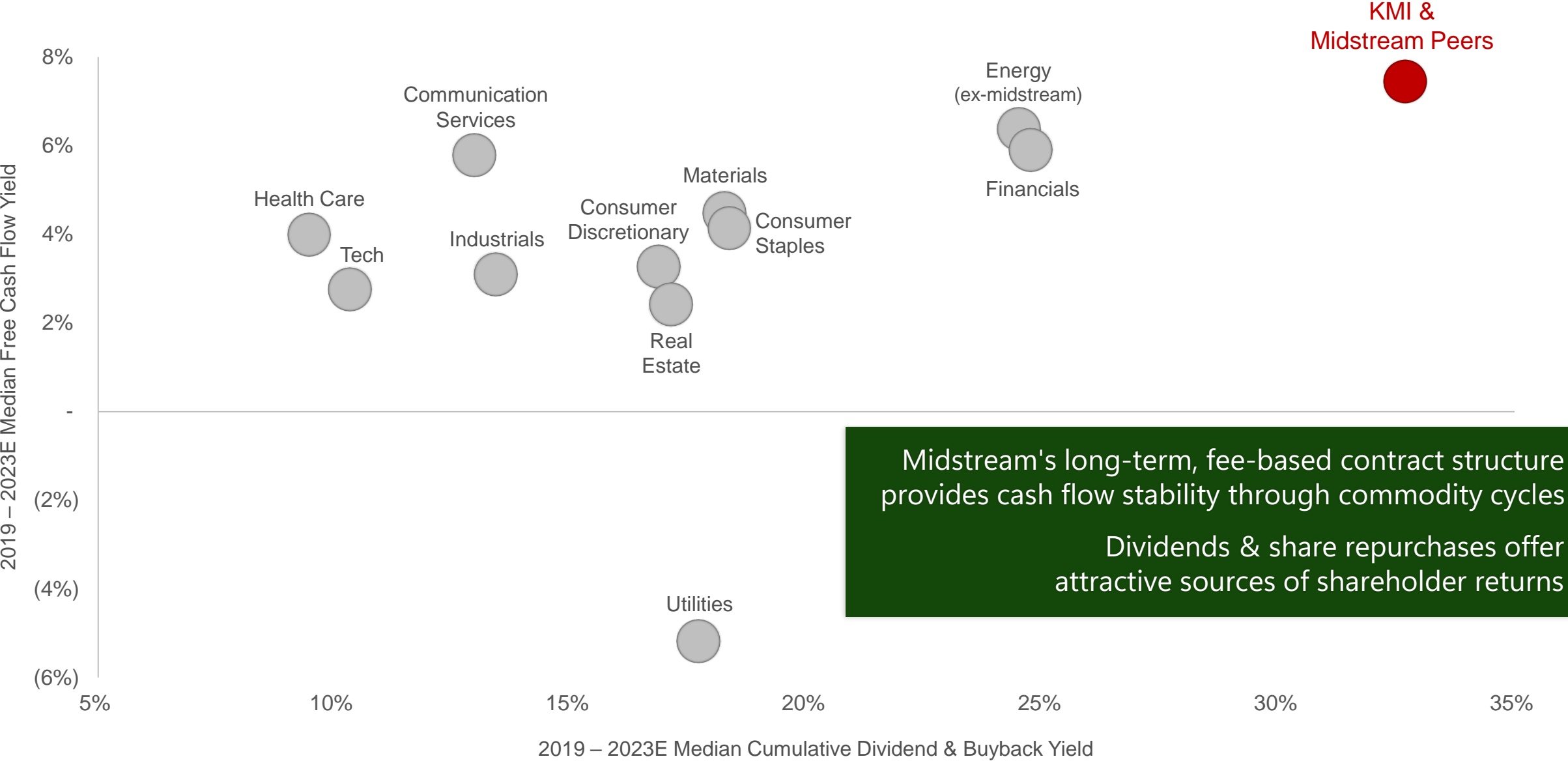
*Robust macro backdrop driving tremendous investment opportunities*



## MANAGED FOR SHAREHOLDERS BY SHAREHOLDERS

*Highly aligned leadership, with long-term, strategic focus*

# Midstream Generates Substantial Free Cash Flow



Midstream's long-term, fee-based contract structure provides cash flow stability through commodity cycles

Dividends & share repurchases offer attractive sources of shareholder returns

Note: Data from Bloomberg for companies in the S&P500 as of 12/29/2023. KMI's midstream peers include ENB CN, EPD, ET, MPLX, OKE, PAA, TRP CN, and WMB. FCF calculated as Cash Flow From Operations less Capital Expenditures.

# Significant Cash Generated and Returned to Shareholders

\$18 Billion Returned to Shareholders; \$8 Billion Returned to Debt Holders

## Actions taken & uses of cash flow since 2016

40%

### Increased Dividend

- Grew the dividend from \$0.50 to \$1.13 per share
- Maintained strong dividend coverage

20%

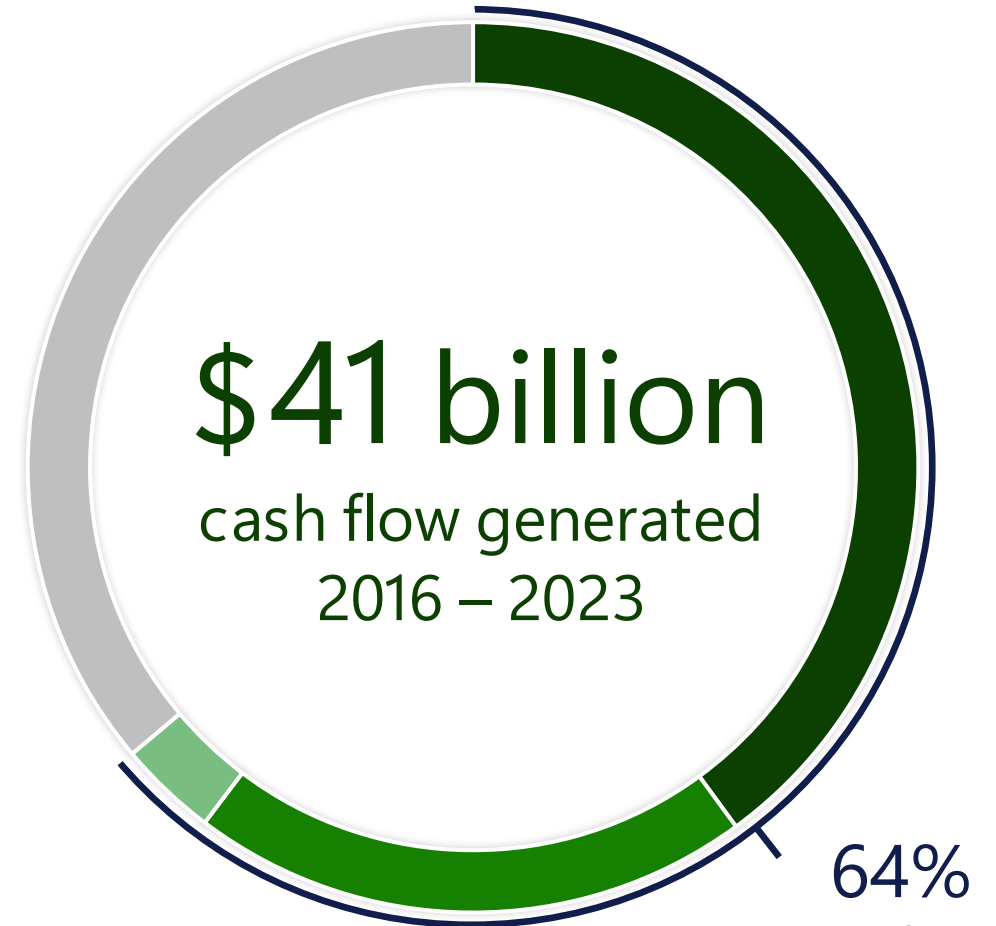
### Decreased Leverage

- ~1.1x reduction to Net Debt / Adjusted EBITDA to ~4.2x
- Improved credit rating to BBB

4%

### Opportunistic Share Repurchases

- Repurchased ~86 million shares (~4%) for ~\$1.5 billion



64%  
returned to  
equity & debt holders

# Bullish Outlook for U.S. Natural Gas Demand

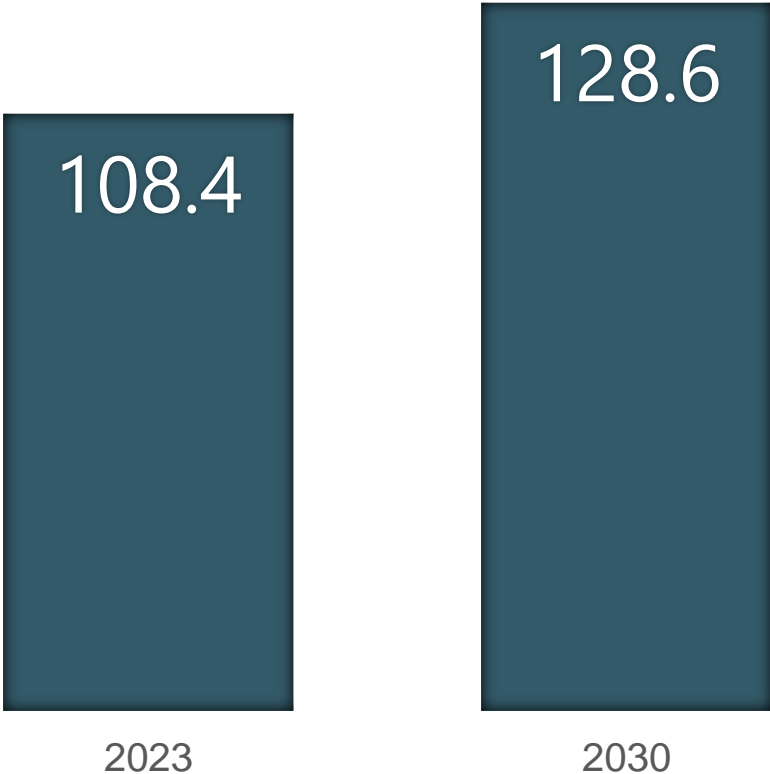
U.S. Demand Expected to Grow Nearly 20% by 2030

U.S. NATURAL GAS DEMAND FORECAST bcf/d

**+20 bcf/d**  
of growth driven by

---

- +16 bcf/d LNG feedgas
- +3 bcf/d exports to Mexico
- +3 bcf/d Industrial



# Core Holding in Any Portfolio

Generating Robust Cash Flow & Returning Significant Value to Shareholders

Largest natural gas transporter in the U.S.

Extensive network moving ~40% of U.S. natural gas production

~13% owned by management & board

Highly aligned management with significant equity interests

~\$8.2 billion 2024 budget Adj. EBITDA

+8% increase from 2023

~6.5% current dividend yield

7<sup>th</sup> consecutive annual dividend increase in 2024

\$3 billion share buyback program

Nearly \$900 million repurchased over the past two years  
~\$1.5 billion of repurchase program remaining

# OUTLOOK

*Kimberly Dang*



WIC Diamond Compressor Station

# Irreplaceable Infrastructure Portfolio

Delivering energy to improve lives & create a better world

### Largest natural gas transmission network

- ~70,000 miles of natural gas pipelines move ~40% of U.S. natural gas production
- Have interest in 702 bcf of working storage capacity, ~15% of U.S. capacity

### Largest independent transporter of refined products

- Transport ~1.7 mmbbl/d of refined products to coastal demand markets
- ~9,500 miles of refined products and crude pipelines

### Largest independent terminal operator

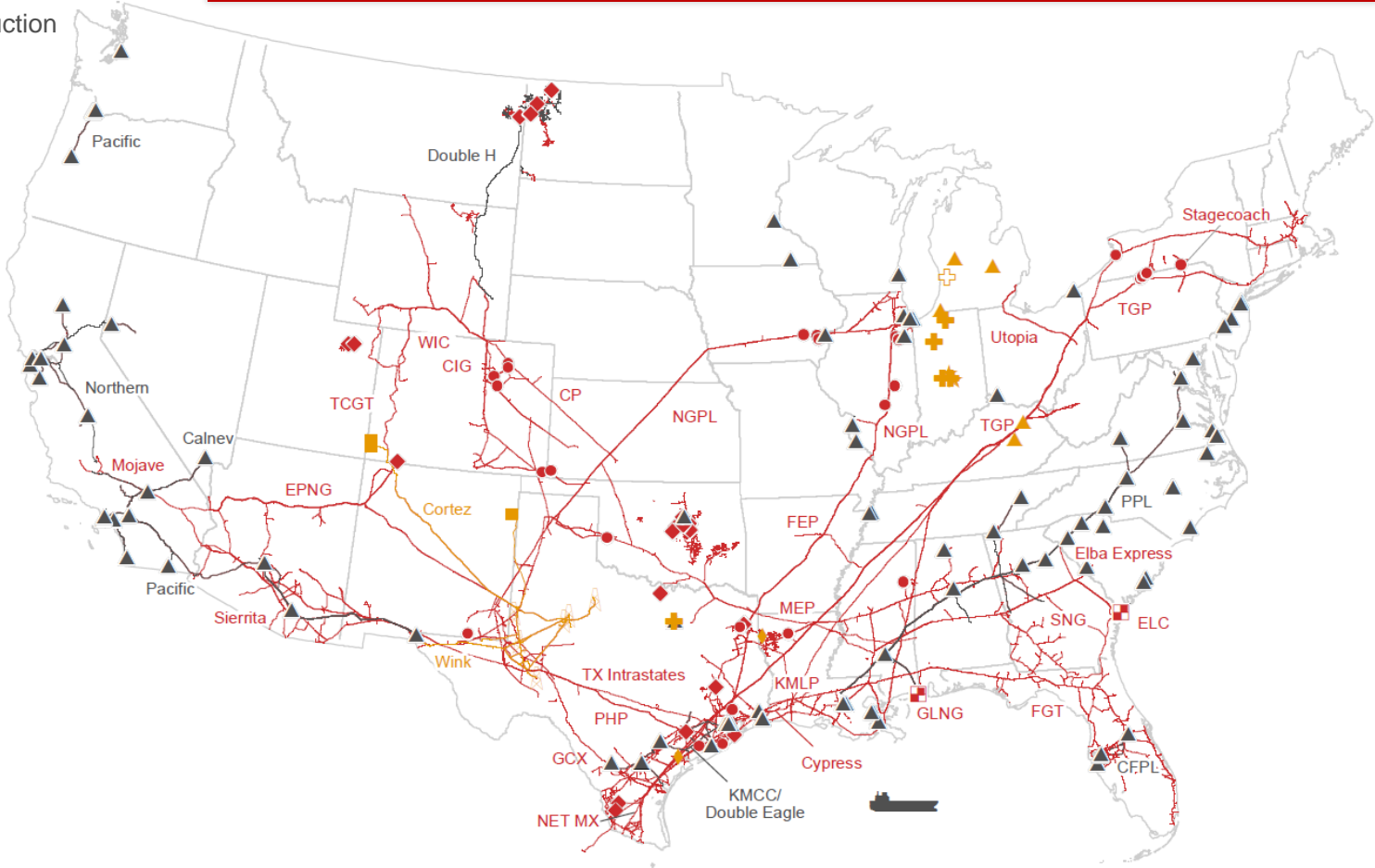
- 139 terminals & 16 Jones Act vessels
- 135 mmbbl of total liquids storage capacity

### One of the largest CO<sub>2</sub> transporters

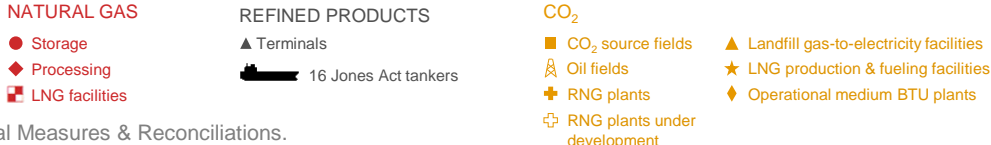
- ~1,500 miles of CO<sub>2</sub> pipelines with transport capacity of ~1.5 bcfd
- Produce and transport CO<sub>2</sub> for enhanced oil recovery

### Growing Energy Transition Portfolio

- Up to 6.4 bcf<sup>(a)</sup> of RNG production capacity by 2H 2024



### Business Mix



Note: Volumes per 2024 budget. Business mix based on 2024 budgeted Total Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.  
 a) Annual capacity at KM share.  
 b) Refined Products includes 14% from our Products Segment and 12% from our Terminals Segment.

# How Kinder Morgan Drives Shareholder Value



## Natural Gas Focus

~64% of KM cash flows come from natural gas  
Transport ~40% of U.S. natural gas production



## Balance Sheet Strength

BBB investment grade balance sheet  
~3.9x YE 2024B Net Debt / Adjusted EBITDA



## High-Returning Growth Projects

~\$3 billion of committed projects at <5x EBITDA build multiple



## Predictable and Growing Cash Flow

~68% of cash flows take-or-pay or hedged  
+14% Adj. EPS and +8% Adj. EBITDA growth expected in 2024

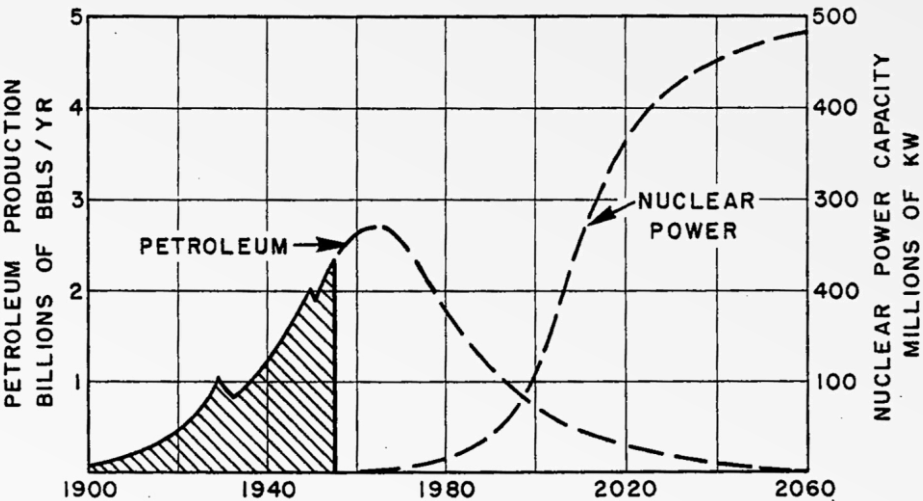


## Returns to Shareholders

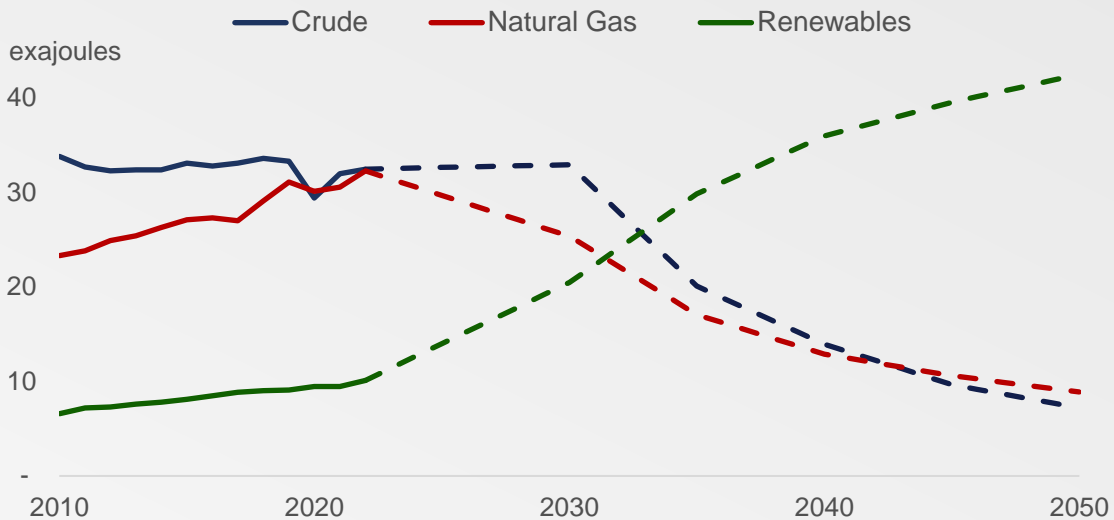
2023 dividends and buybacks of over \$3 billion (~8% return per share)

# Predictions of Extreme Declines Have Not Translated into Reality

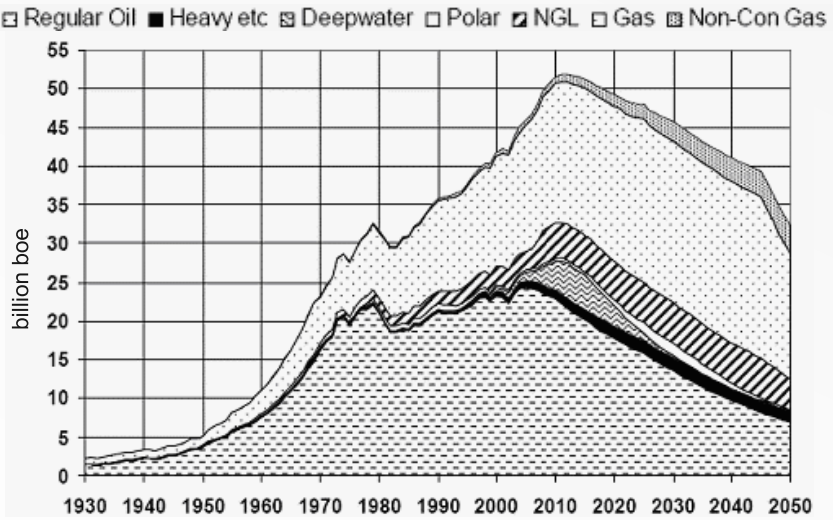
## 1956 SHELL U.S. ENERGY SUPPLY FORECAST



## 2023 IEA U.S. ENERGY SUPPLY FORECAST



## 2006 ASPO GLOBAL OIL & GAS PRODUCTION FORECAST



Cost, reliability & availability of energy shape how future demand is met

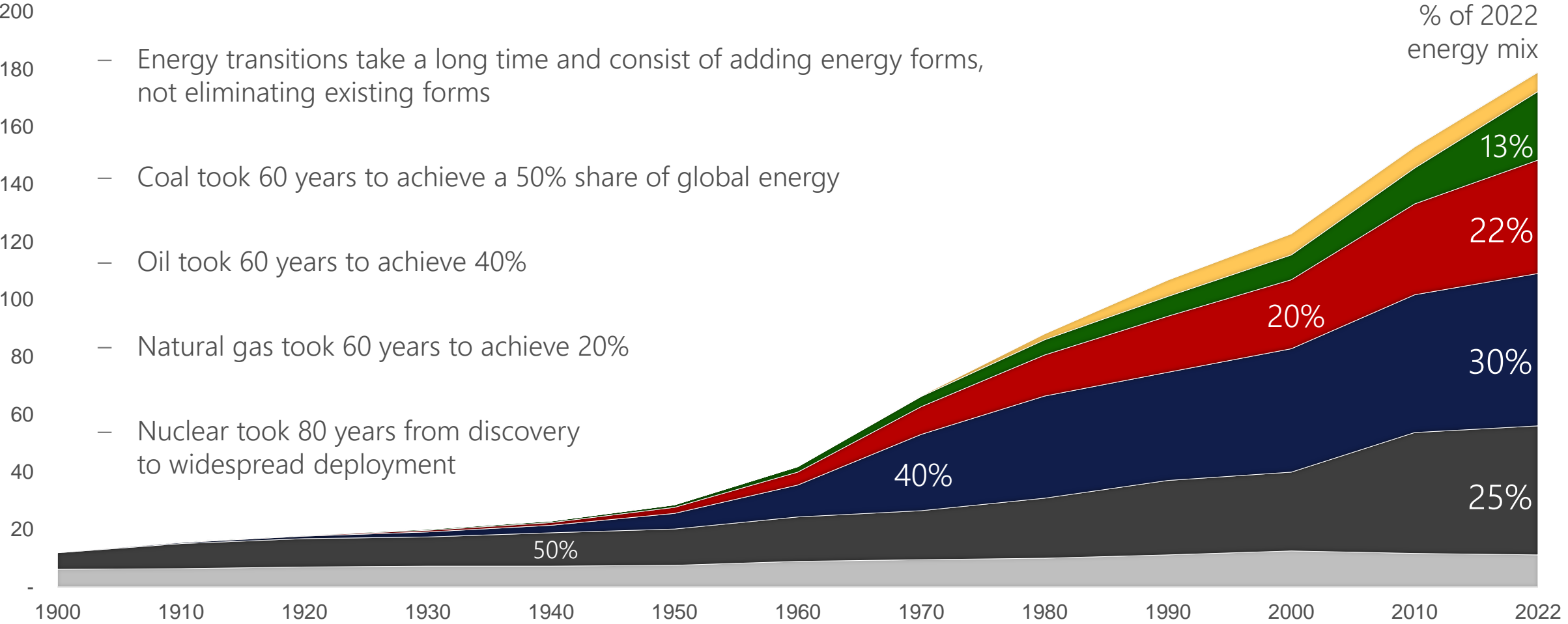
Top Left: M. K. Hubbert, Nuclear Energy and the Fossil Fuels, Shell Development Company, 95, 1956. Top Right: Based on IEA data from the IEA (2023) World Energy Outlook Announced Pledges Scenario, World Energy Outlook 2023 – Analysis – IEA. All rights reserved. Bottom Left: Association for the Study of Peak Oil and Gas 2006 Base Case Oil & Natural Gas Forecast.

# Energy Transitions Take Time

Our Assets and Services Will Be Needed for a Very Long Time

GLOBAL ENERGY MIX BY FUEL PWh

■ Biomass ■ Coal ■ Oil ■ Natural gas ■ Renewables ■ Nuclear

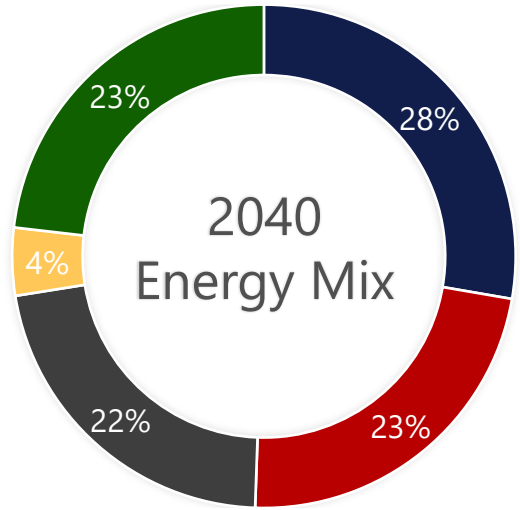
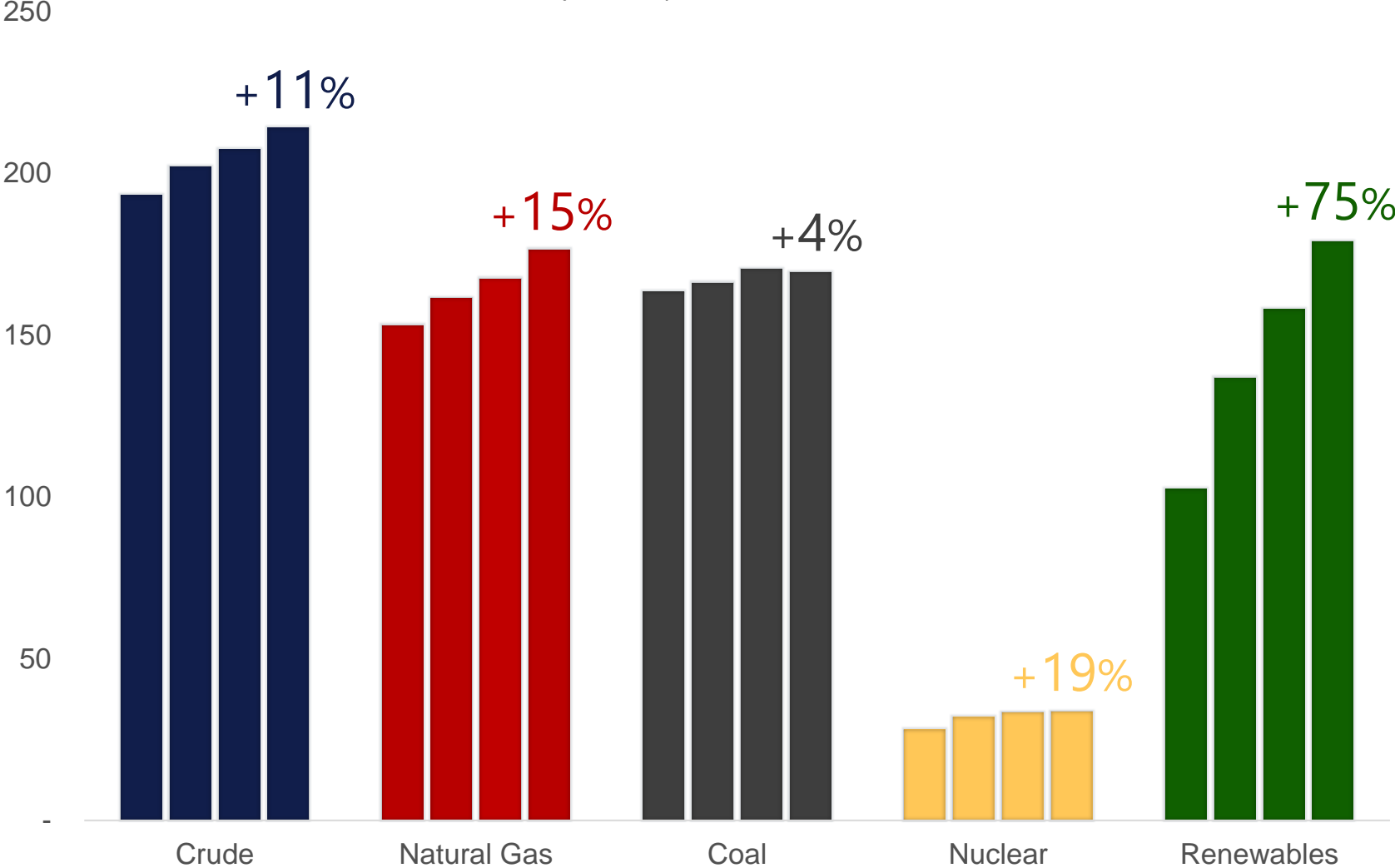


- Energy transitions take a long time and consist of adding energy forms, not eliminating existing forms
- Coal took 60 years to achieve a 50% share of global energy
- Oil took 60 years to achieve 40%
- Natural gas took 60 years to achieve 20%
- Nuclear took 80 years from discovery to widespread deployment

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

# The Fuels We Move Will Continue to Be Needed

**GLOBAL ENERGY DEMAND**  
quad btu | 2023, 2030, 2035, 2040

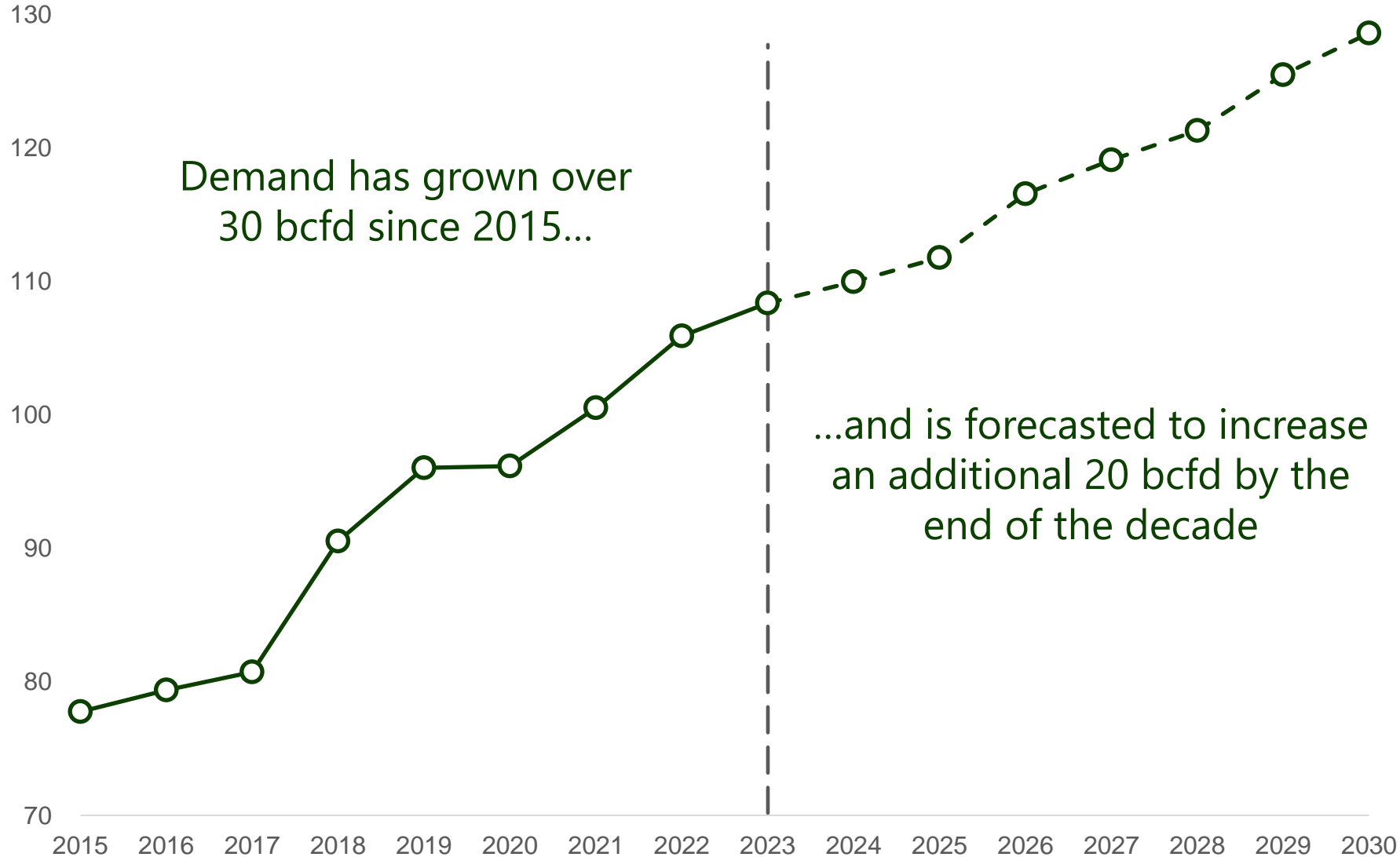


All energy sources will be needed to meet future demand

Source: EIA 2023 International Energy Outlook Reference Case.

# Demand for U.S. Natural Gas Projected to Grow

U.S. NATURAL GAS DEMAND bcf/d



2023 – 2030  
Natural Gas Demand

**+19%**

Increase in total  
U.S. demand

**+98%**

Increase in LNG &  
Mexican exports

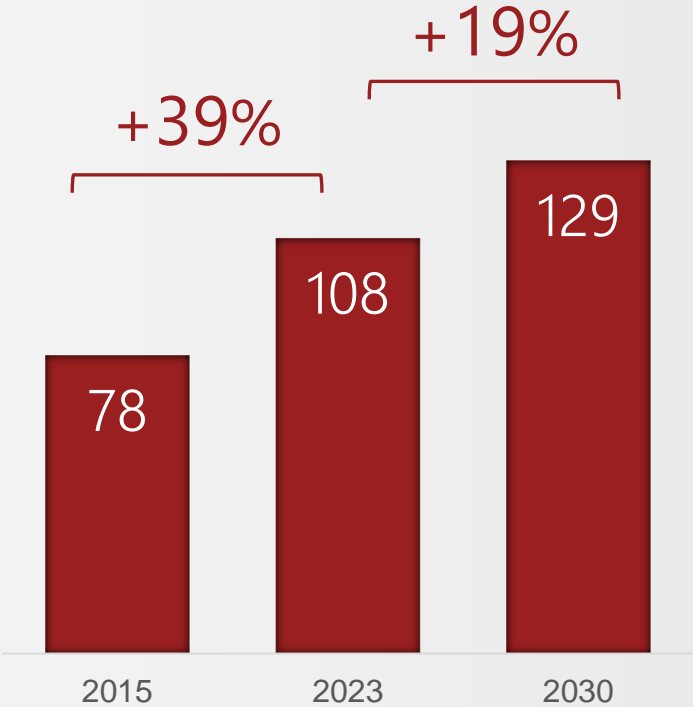
**+12%**

Increase in  
industrial demand

# Rising Demand Benefitting Our Natural Gas Transportation Business

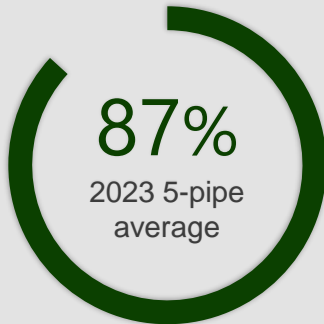
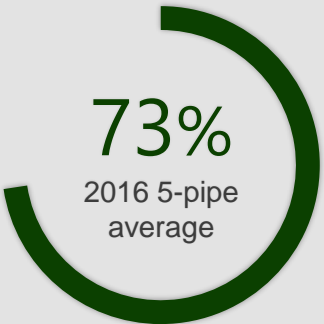
Increased demand leading to

## U.S. NATURAL GAS DEMAND bcfd



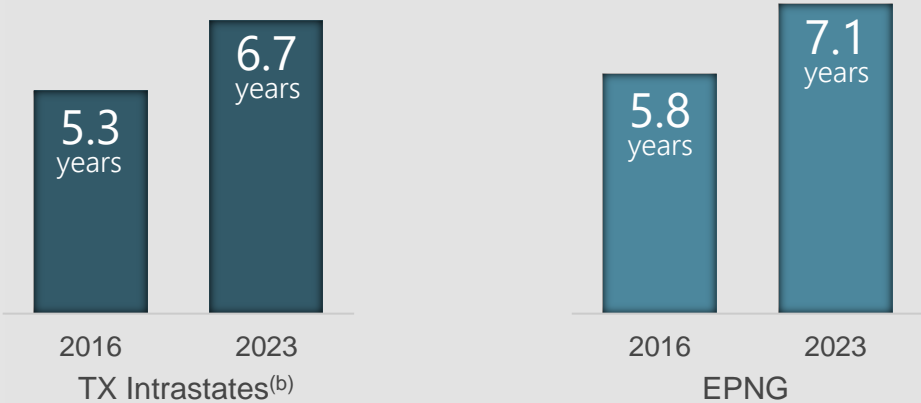
Source: U.S. demand figures per Wood Mackenzie, North America Gas 10-Year Investment Horizon Outlook, October 2023.  
 (a) Capacity weighted average utilization of TGP, EPNG, NGPL, SNG, and the Texas Intrastates. Utilization is calculated as billed throughput divided by designed pipeline capacity.  
 (b) TX Intrastate average remaining contract life includes term sale portfolio.

- INCREASED PIPELINE UTILIZATION<sup>(a)</sup>



- INCREASED CONTRACT TERMS AND/OR RATES

EXAMPLES



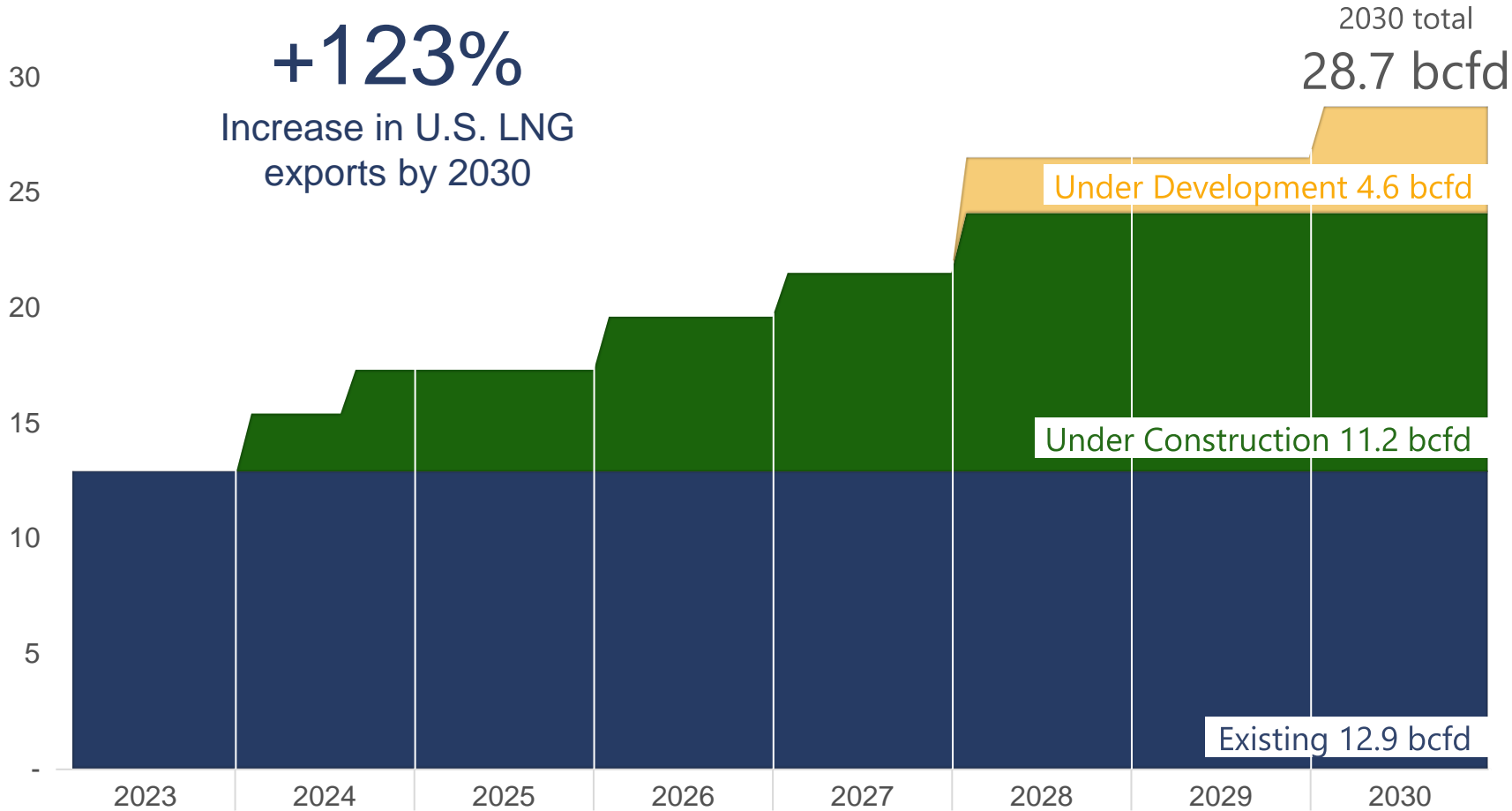
- NEW PROJECTS

~\$2.2 billion of natural gas projects in our backlog; expected to grow over time

# LNG Exports Drive Natural Gas Demand Growth

U.S. LNG EXPORT CAPACITY in bcf/d

■ Existing ■ Under Construction ■ Under Development



**+123%**  
Increase in U.S. LNG exports by 2030

2030 total  
28.7 bcf/d

Under Development 4.6 bcf/d

Under Construction 11.2 bcf/d

Existing 12.9 bcf/d

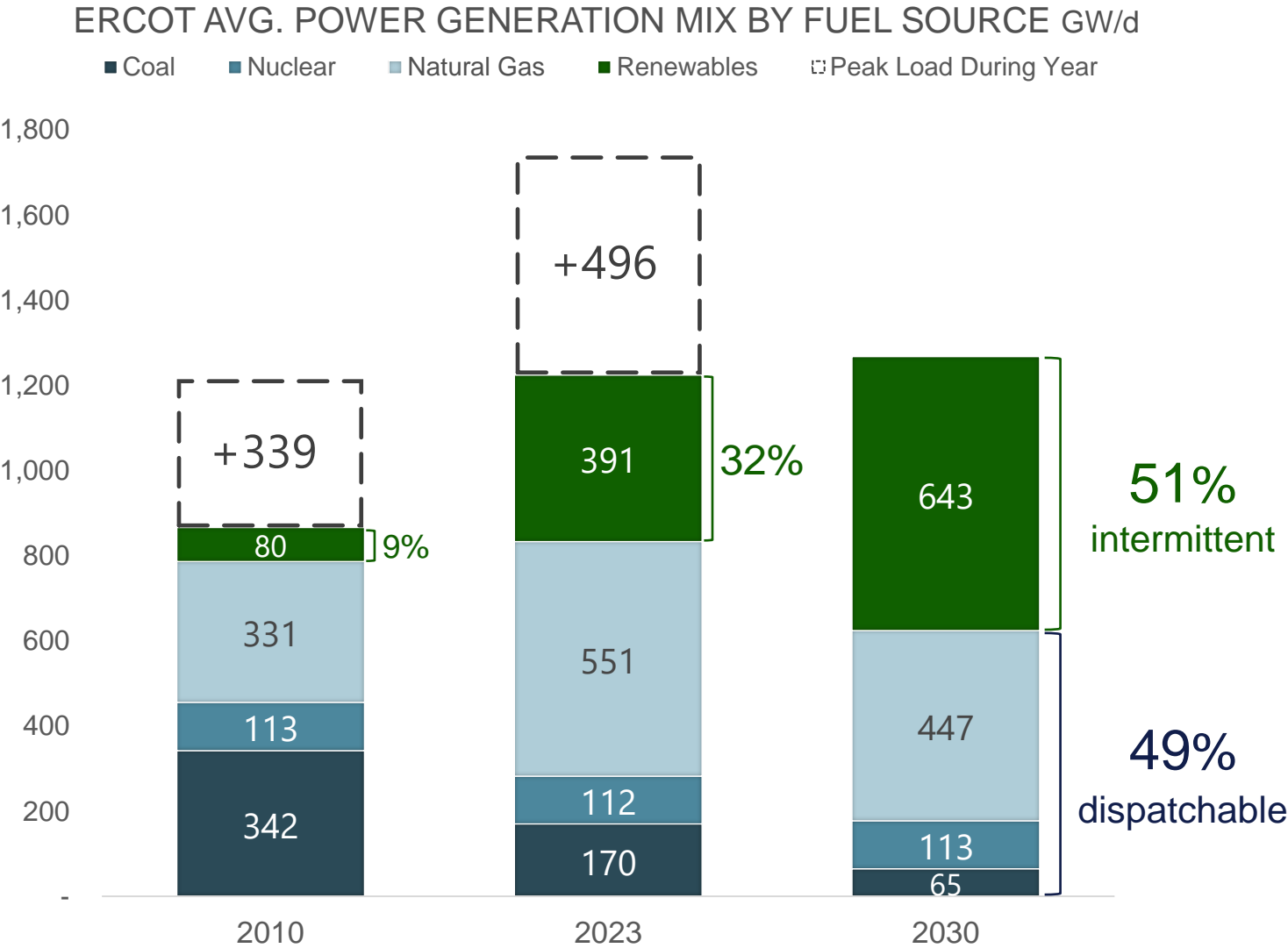
Growth primarily along the Texas & Louisiana gulf coast with great overlap with KM assets

KM has contracts in place to supply ~10 bcf/d of this by 2025, and we are pursuing up to ~13 bcf/d more

This growth benefits our upstream networks which access diverse, low-cost natural gas supply, as well as storage

Note: This forecast has not been adjusted for the announced delayed in-service of Golden Pass.  
Source: Wood Mackenzie, North America Gas 10-Year Investment Horizon Outlook, October 2023.

# Growing Intermittency Requires Additional Natural Gas Capacity



Additional natural gas generation will be needed to backstop intermittent renewables and cover increased demand during severe weather events

- For example, in an extreme scenario, natural gas generation would have needed to increase by 419 GW and 887 GW in 2010 & 2023, respectively, to cover both lost renewable generation and added demand

However, critical pipeline capacity is nearly full today and not sufficient to cover greater peaks in future power demand

Plus, other demand sources (LNG, exports to Mexico, industrials) are increasingly competing for natural gas supply

This dynamic requires more natural gas transportation & storage capacity and increases the value of existing infrastructure

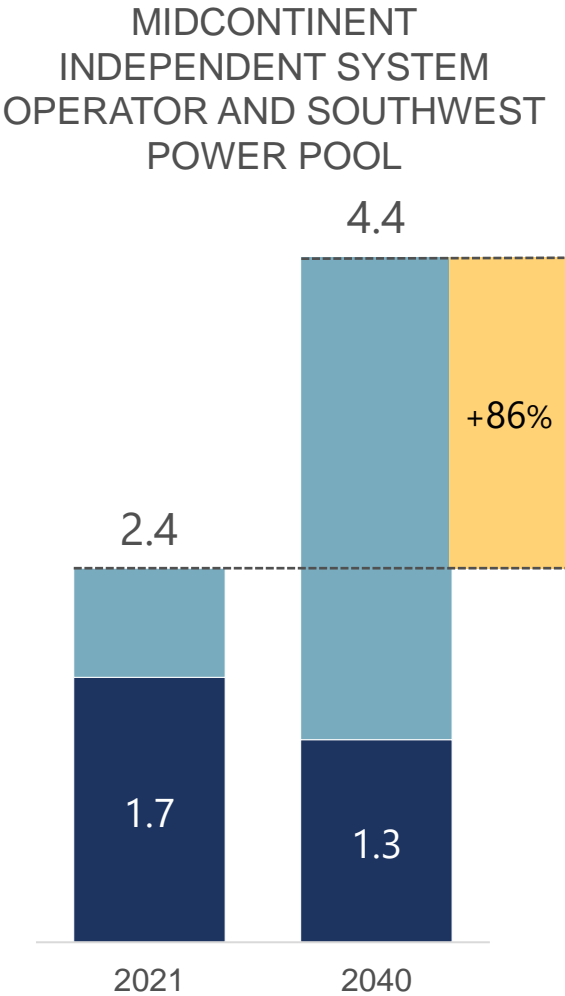
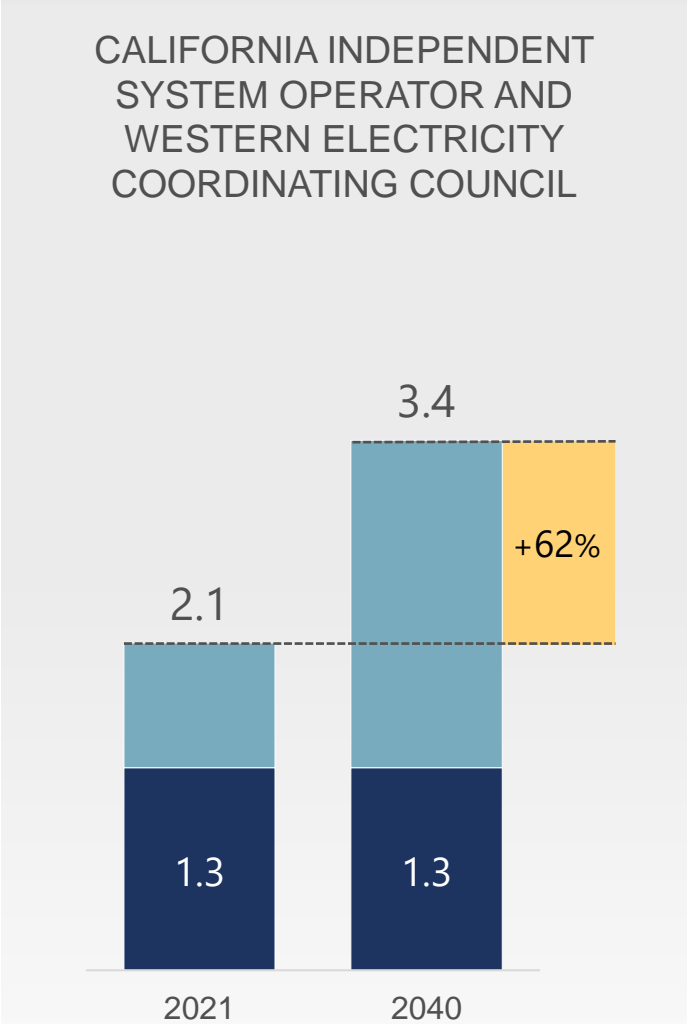
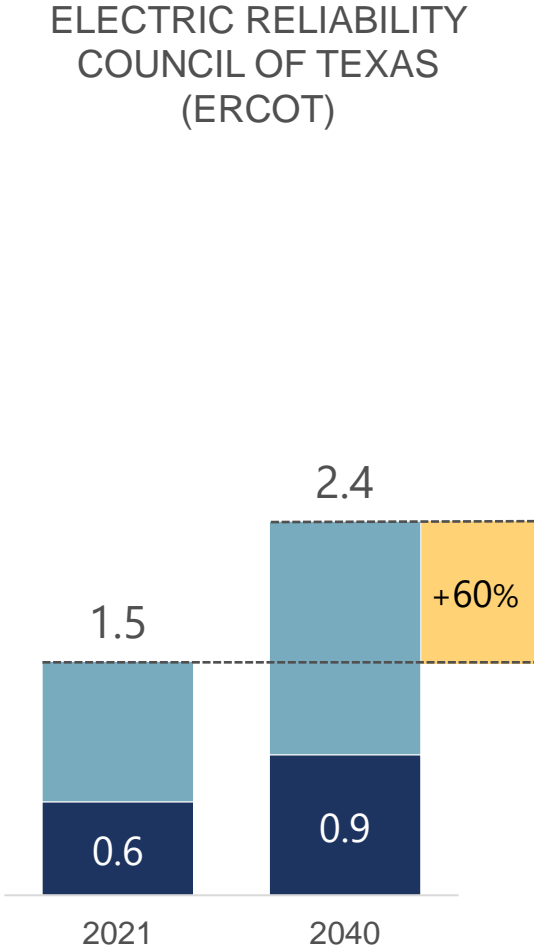
Source: ERCOT 2010 & 2023 Fuel Mix Report. 2030 per the EIA's 2023 Annual Energy Outlook. Peak load during year estimate not available for 2030.

# Natural Gas is Key to Serving Peak Power Demand

Additional Dispatchable Gas-Fired Power Generation & Pipeline Capacity Will Be Needed to Complement Intermittent Renewables

**AVERAGE AND PEAK DAY NATURAL GAS DEMAND FOR POWER BY OPERATOR in TWh per day**

■ Average ■ Peak

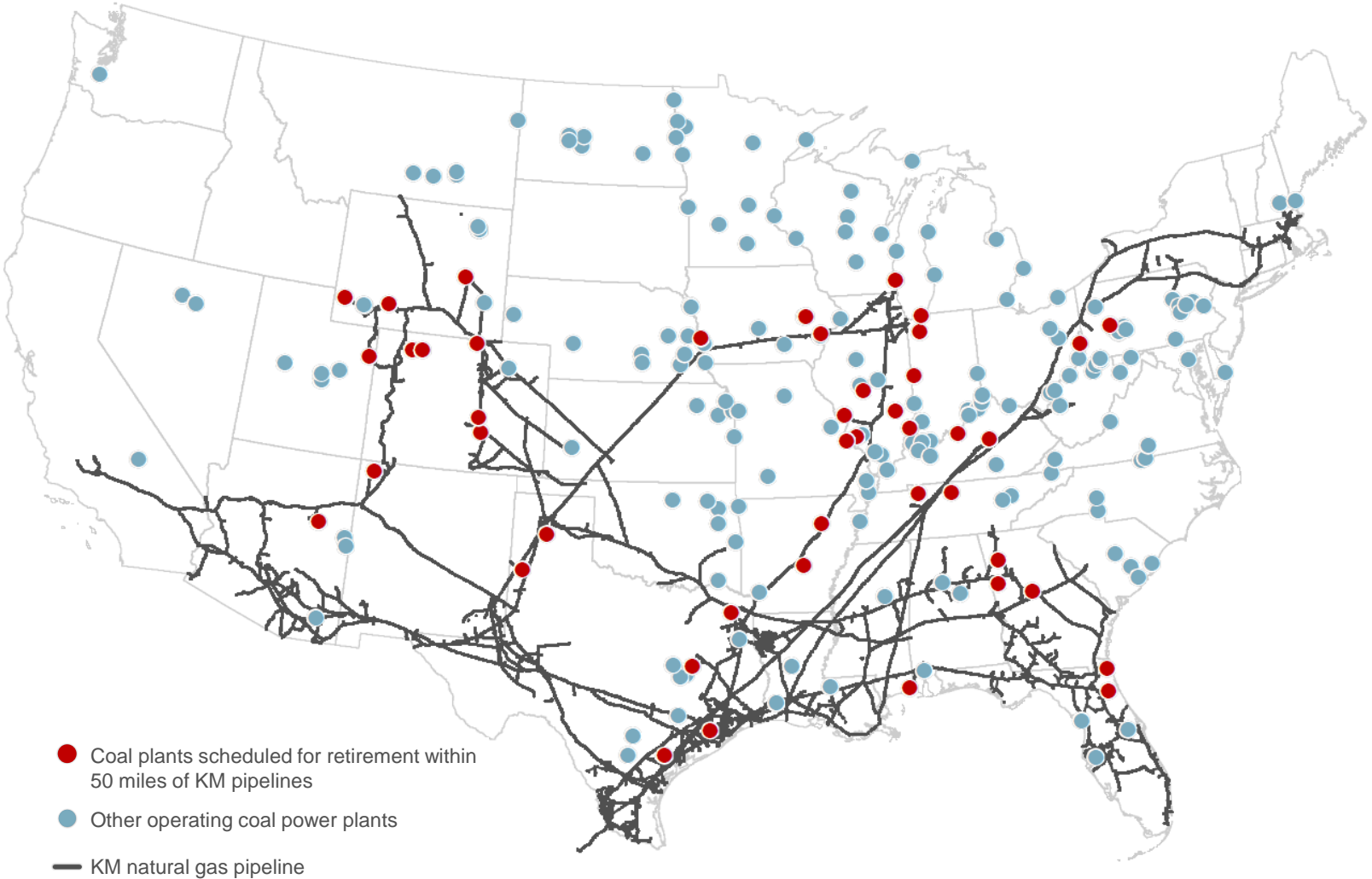


KM offers deliverability

Utilities will need to reserve pipeline capacity to cover peak demand days

Source: McKinsey & Company.

# Coal-to-Natural Gas Conversions Present an Additional Source of Power Demand



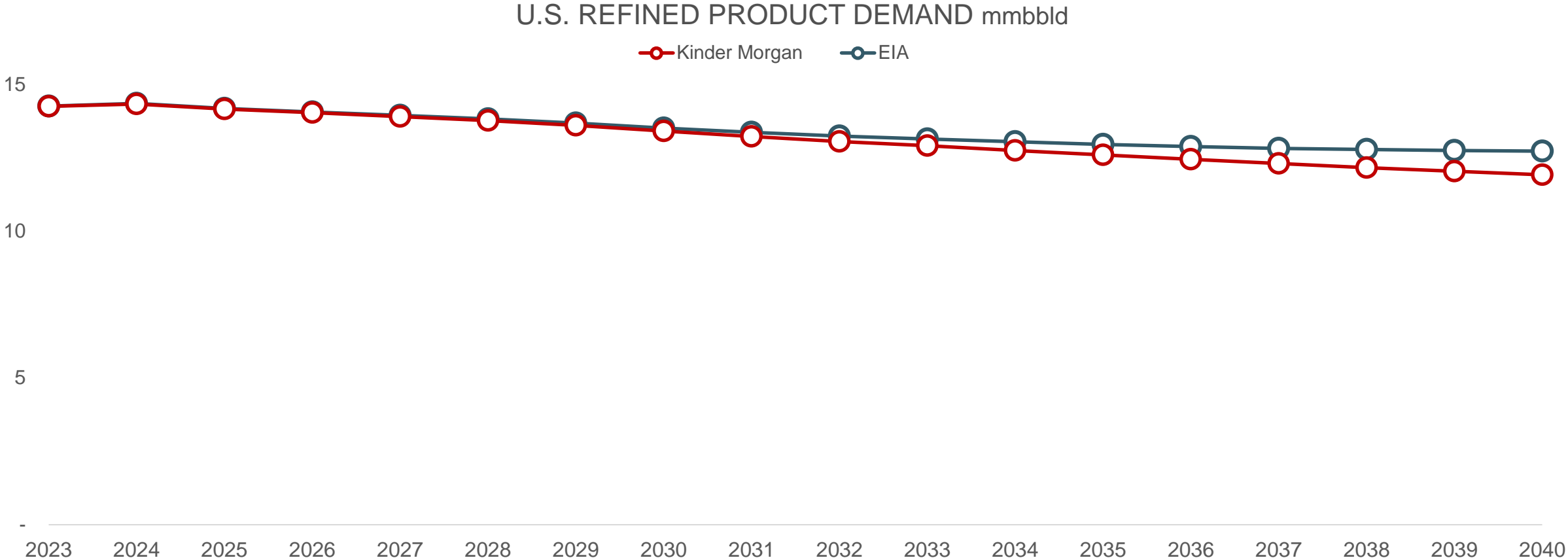
~230 coal-fired power plants operating in the U.S. today (~200 GW of capacity)

~45 coal-fired power plants slated for retirement are located within 50 miles of our pipelines

Converting to natural gas-fired generation could reduce emissions by nearly 45% on average

Source: EIA coal-fired power plant and emissions data as of 2022.

# Forecasting U.S. Refined Product Demand to Remain Persistent



## KM Forecast to 2040

**23%**

of U.S. vehicle fleet comprised of EVs in 2040<sup>(a)</sup>

**47%**

of U.S. new car sales are EVs in 2040<sup>(a)</sup>

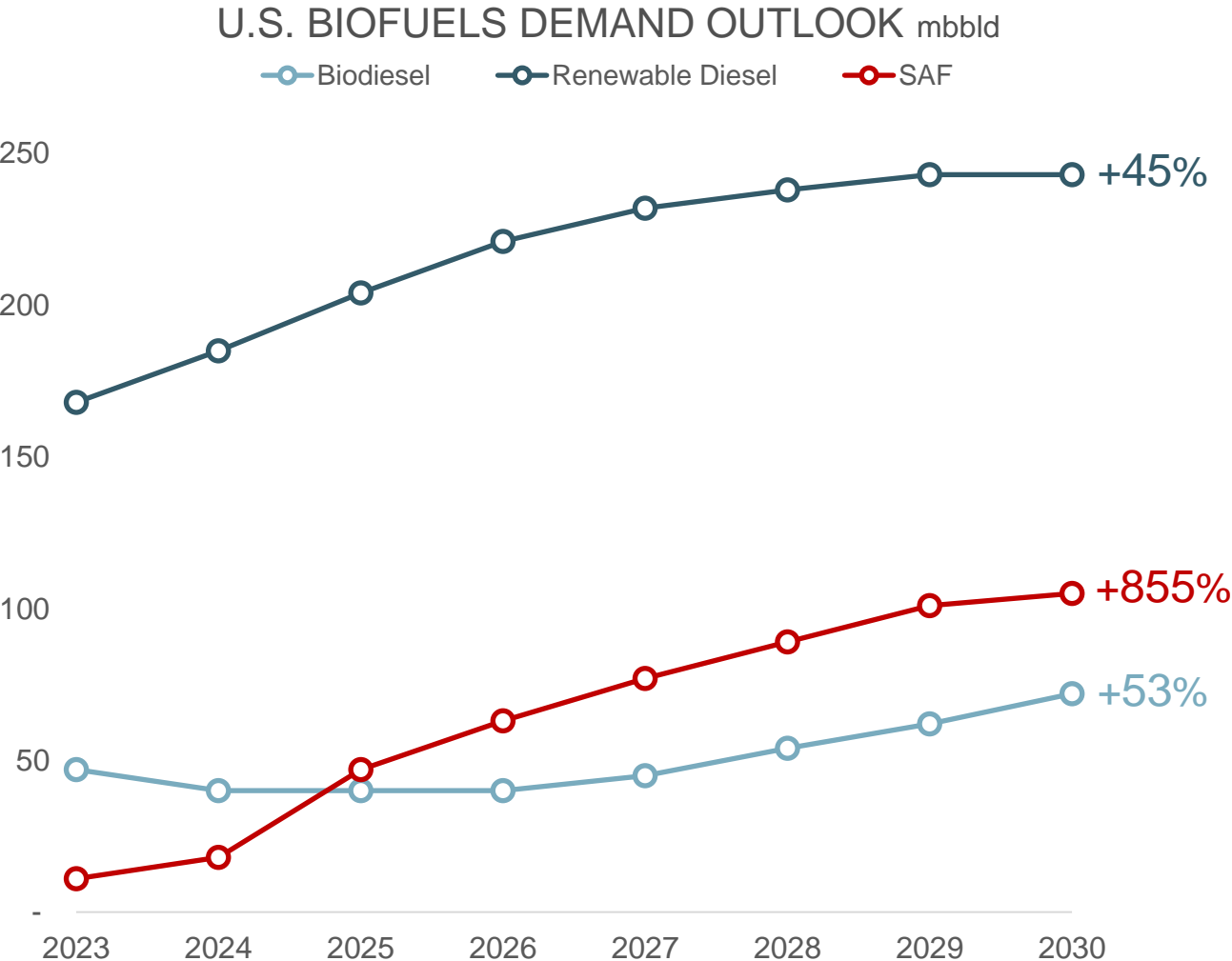
**-1%**

annual decrease in U.S. refined product demand

Volume declines expected to be largely offset by rate adjustments, renewable fuels & non-jurisdictional revenue growth

Source: KM internal forecast and EIA 2023 Annual Energy Outlook.  
 a) Based on KM assumptions.

# Constructive Outlook for Liquid Biofuel Demand in the U.S.

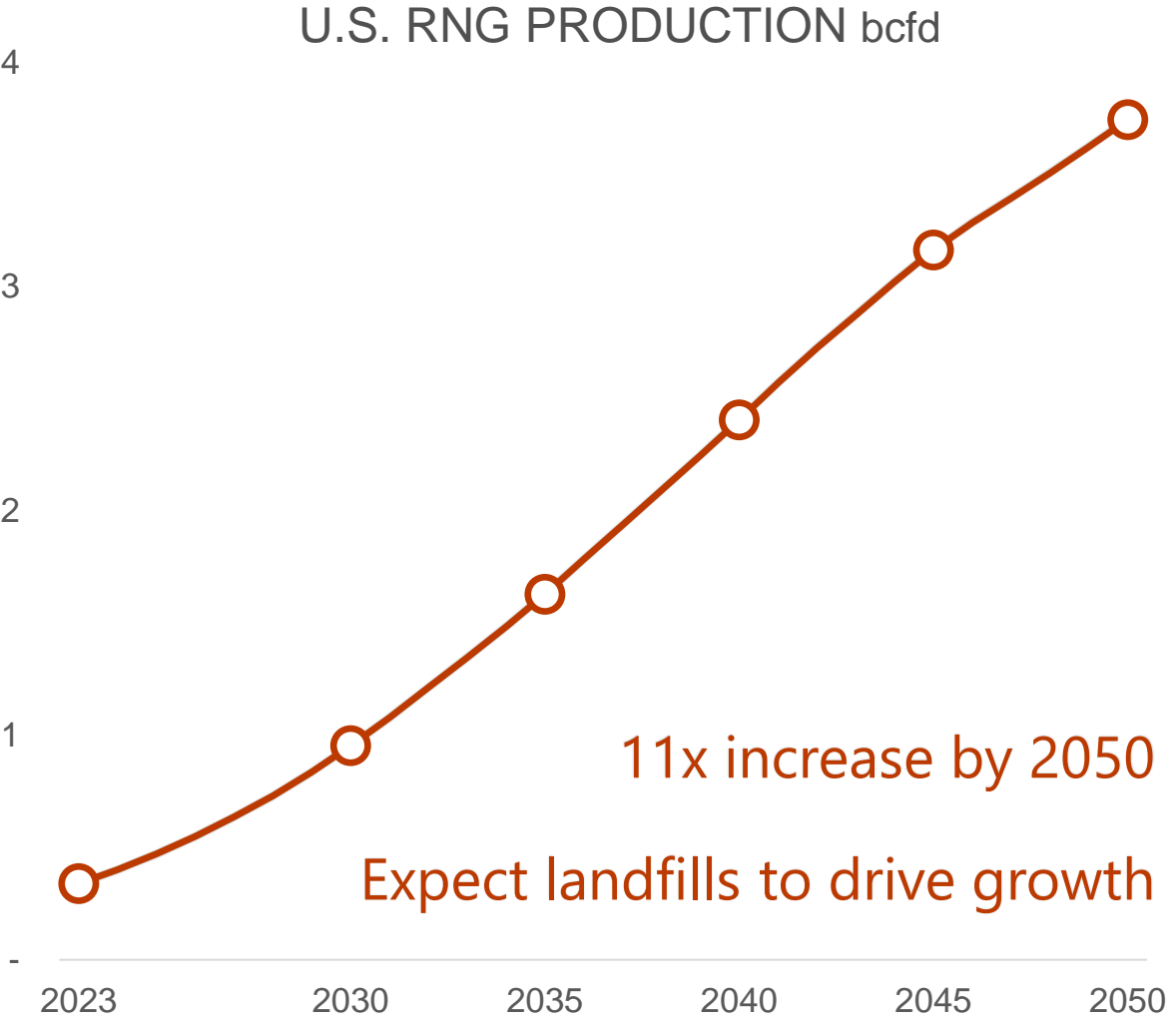


2023 VOLUMES mbbld		
	Terminal and pipeline throughput <sup>(a)</sup>	Total variance to 2022
ethanol	173	—
biodiesel	14	8%
renewable diesel	25 <sup>(b)</sup>	150%
renewable feedstocks	5	11%

Leveraging existing assets to handle liquid biofuels and feedstocks

Left Source: S&P Global.  
 (a) Includes the throughput from both the Products and Terminals segments.  
 (b) Excludes potential renewable diesel volumes below 5% statutory level due to insufficient reporting.

# Growing Demand for Renewable Natural Gas



Lower-carbon energy source that can be used as a direct substitute for natural gas

Technology & infrastructure are proven, and projects generate attractive returns

Long-term transportation market demand supported by regulatory tailwinds

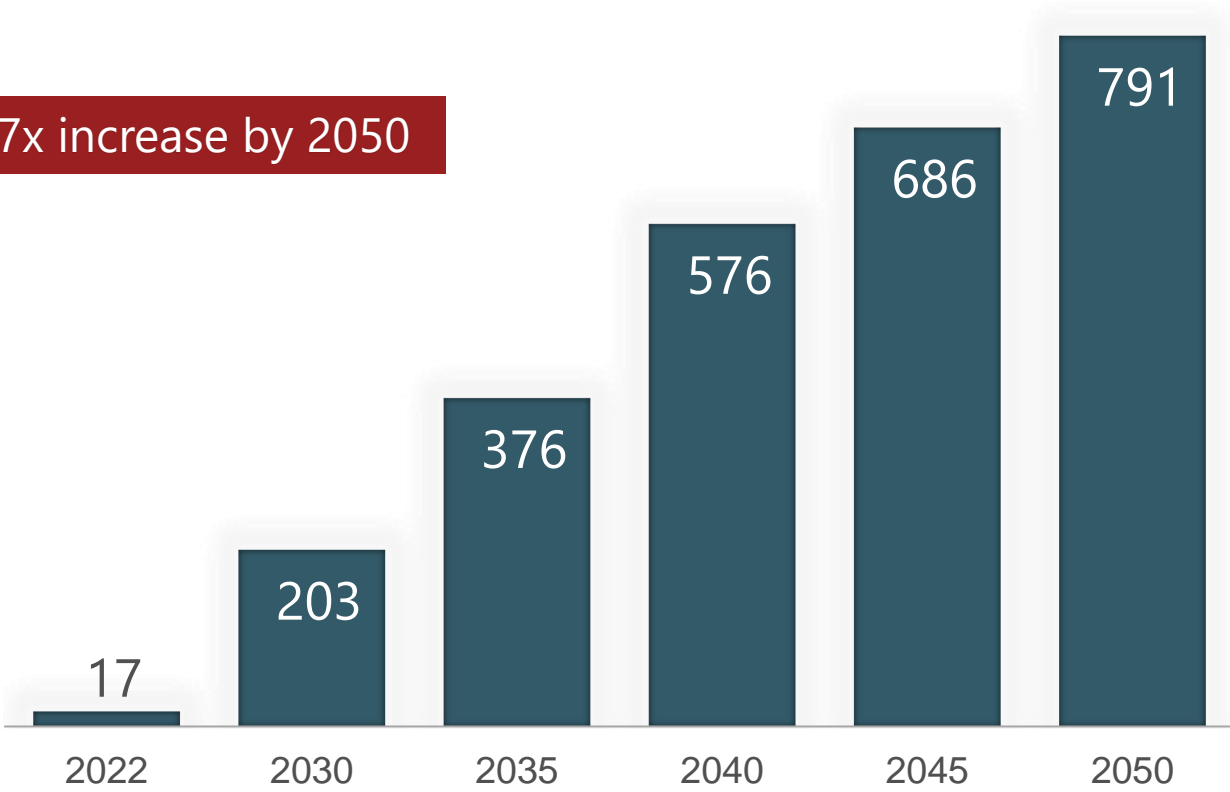
Demand in fixed-price voluntary market is expected to grow as other users (utilities, LDCs, industrials) decarbonize

Sources: Wood Mackenzie, North America Gas 10-Year Investment Horizon Outlook, October 2023. Includes all forms of RNG production.

# Carbon Capture Will Be Required to Meet Emission Reduction Goals

U.S. ANNUAL CAPTURED CARBON  
Mt CO<sub>2</sub>

~47x increase by 2050



CCS is pivotal in lowering emissions and potentially achieving carbon neutrality

- Lowers emissions associated with continued hydrocarbon use
- Helps decarbonize energy intensive industries, like cement and steel production
- Can be coupled with natural gas to provide grid stability in the form of dispatchable, lower-carbon power generation

KM has the expertise to participate across the entire CCS value chain

Source: Based on IEA data from the IEA (2023) World Energy Outlook Announced Pledges Scenario, World Energy Outlook 2023 IEA. All rights reserved.

# Committed To Being a Good Steward

Reduce &  
Avoid Methane  
Emissions



~31%

Reduction in methane emissions since 2020

Leak  
Detection



100%

Of our natural gas compressor stations surveyed annually & transitioning to quarterly

Safety  
Culture



20%

Reduction in Employee TRIR since 2017

Continued  
Improvement



B → AA

MSCI score improvement since 2017

Diversity &  
Inclusion



22%

Increase in female employee representation in management since 2018

Investing in  
Lower Carbon  
Fuels



\$1.9bn

Budgeted to invest in natural gas, RNG, RD, renewable feedstocks, and CCS in 2024

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

# How Kinder Morgan Drives Shareholder Value



Natural  
Gas Focus



Balance  
Sheet  
Strength



High-  
Returning  
Projects



Predictable  
& Growing  
Cash Flows



Returning  
Substantial  
Value to  
Shareholders

# FIRESIDE CHAT WITH NATURAL GAS PRESIDENT

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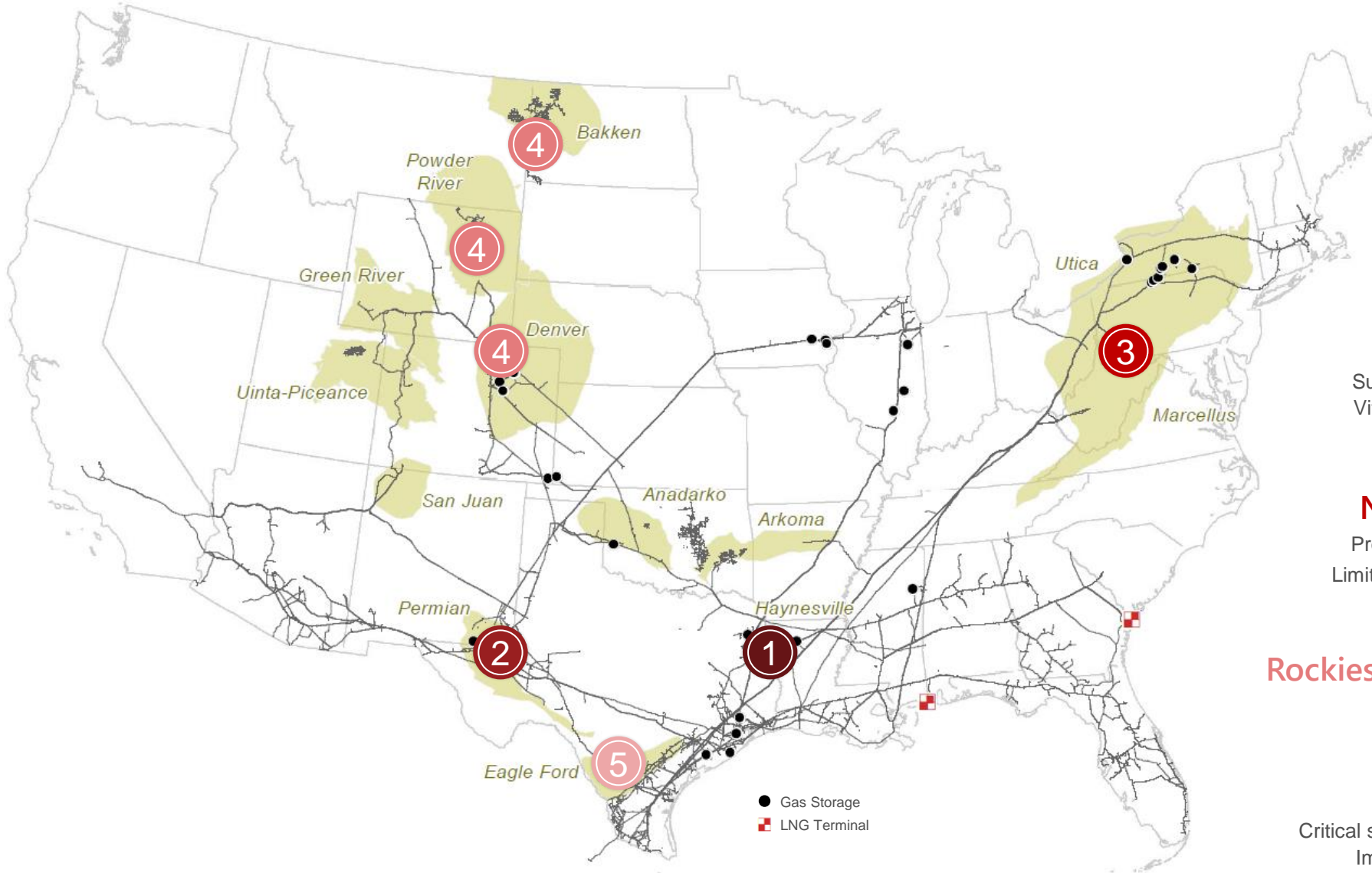
*Sital K. Mody*



# Natural Gas Supply Overview: 2023 – 2030



2023 U.S. Production  
**104 bcf/d**  
 Increase in supply by 2030  
**+19 bcf/d**



**Haynesville** +9 bcf/d of growth **1**  
 Abundant, low-cost, low-nitrogen supply  
 Key to serving Gulf Coast demand markets

**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

**Northeast** +5 bcf/d from the Marcellus/Utica **3**  
 Production constrained despite ample, low-cost supply  
 Limited infrastructure opportunity despite strong demand

**Rockies** +0.7 bcf/d Powder River/DJ; +0.6 bcf/d Bakken **4**  
 Serves Rockies and West Coast demand

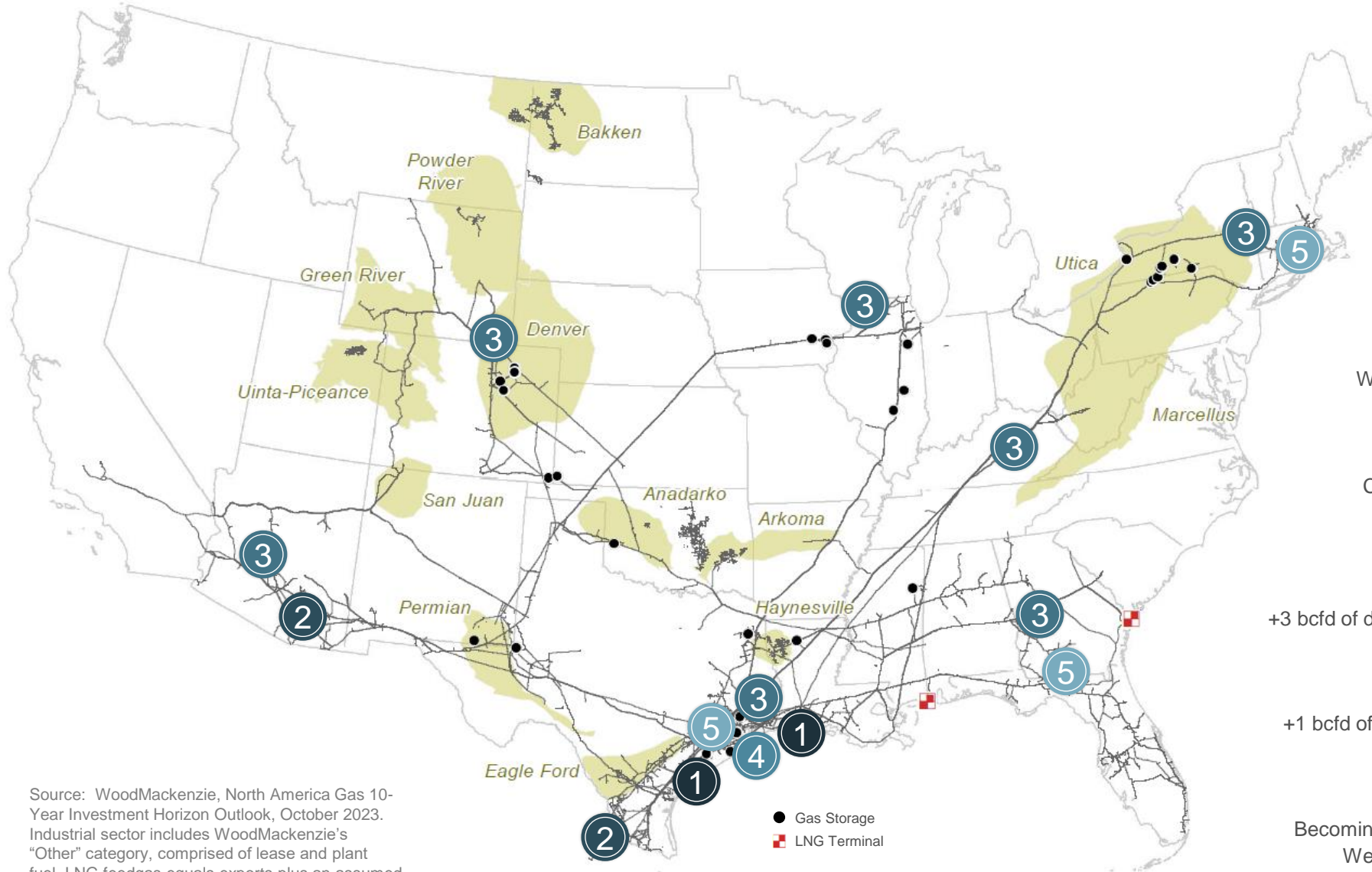
**Eagle Ford** +0.5 bcf/d of growth **5**  
 Critical supply link to Gulf Coast; potential upside to forecast  
 Important source of low-nitrogen gas for LNG facilities

Source: WoodMackenzie, North America Gas 10-Year Investment Horizon Outlook, October 2023.

# Natural Gas Demand Overview: 2023 – 2030



2023 U.S. Demand  
**108 bcf/d**  
 Increase in demand by 2030  
**+20 bcf/d**



Source: WoodMackenzie, North America Gas 10-Year Investment Horizon Outlook, October 2023. Industrial sector includes WoodMackenzie's "Other" category, comprised of lease and plant fuel. LNG feedgas equals exports plus an assumed 9% increase for plant fuel. This volume would otherwise be included in the Industrial category.

- LNG Feedgas ①**  
 +16 bcf/d of Gulf Coast demand growth  
 Well positioned to grow our deliveries over time
- Mexico Exports ②**  
 +3 bcf/d of export demand growth  
 We can deliver into Mexico at multiple strategic points
- Power Demand ③**  
 Capacity needed to backstop intermittent renewables  
 Coal retirements/coal-to-gas conversions
- Industrial Demand ④**  
 +3 bcf/d of demand growth mainly along the TX & LA Gulf Coast
- Residential & Commercial ⑤**  
 +1 bcf/d of growth driven by the Southern U.S. & New England
- Storage**  
 Becoming increasingly important to support variable demand  
 We have interest in 702 bcf of working storage capacity

# Transporter of Choice for LNG Facilities

Advantaged Network Offers Supply Diversity, Connectivity, and Storage

U.S. LNG FEEDGAS & KM TRANSPORT bcf/d

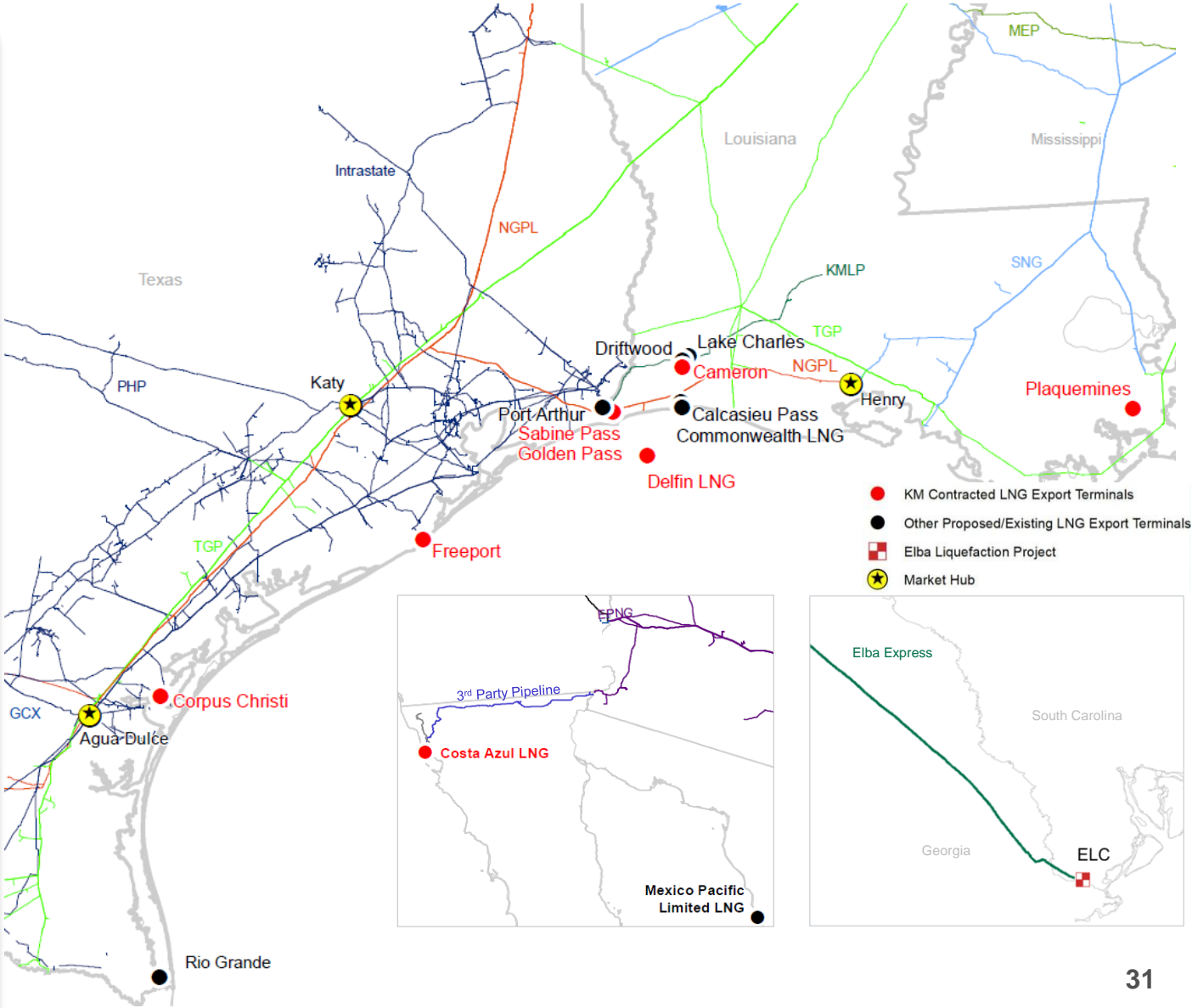
— U.S. LNG Feedgas — KM transport

Long-term contracts to move ~7 bcf/d to facilities today & ~10 bcf/d by the end of 2025

~13 bcf/d of additional opportunities



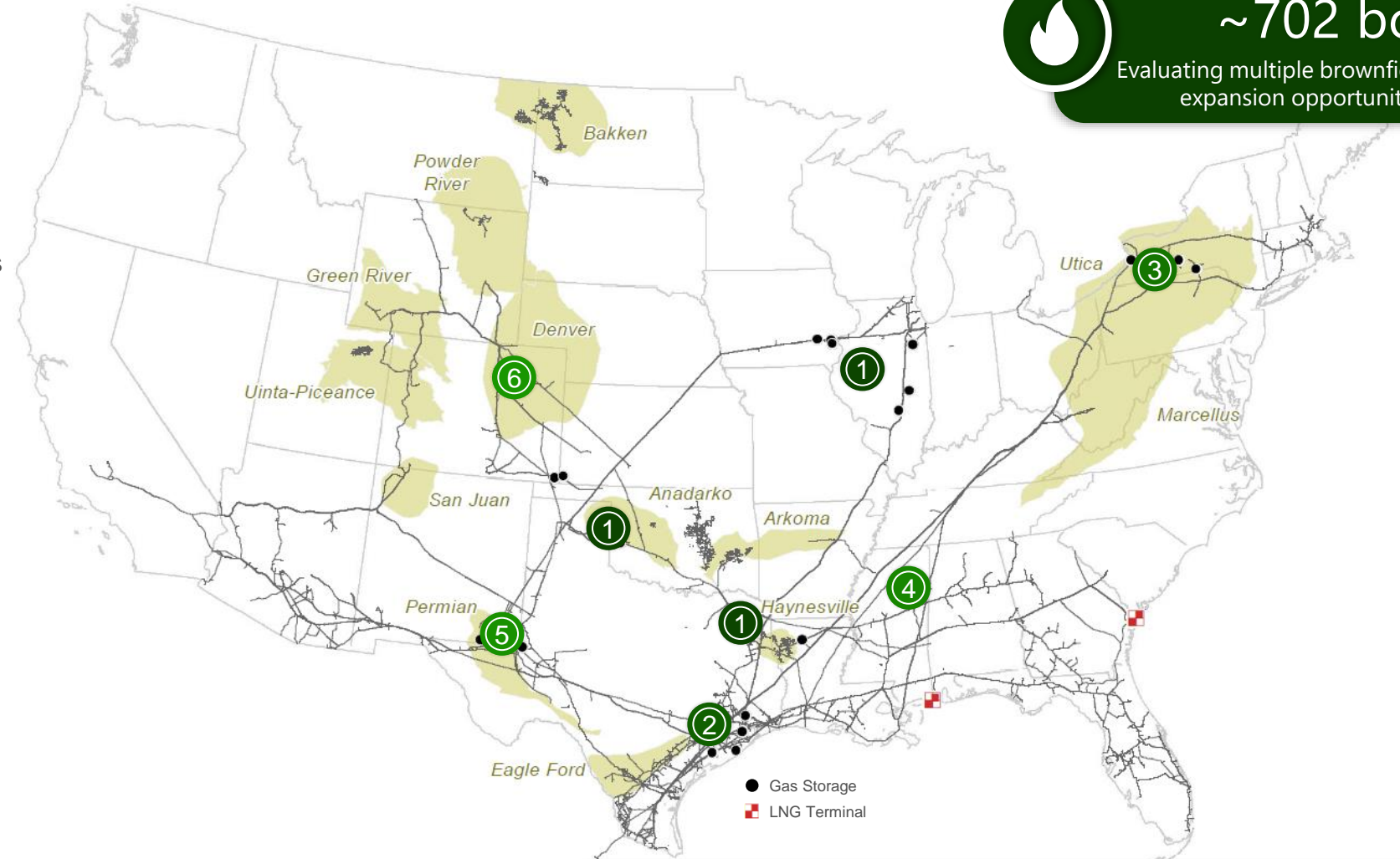
Source: WoodMackenzie, North America Gas 10-Year Investment Horizon Outlook, October 2023.  
 Note: WoodMackenzie exports are multiplied by 1.09 for an estimated feedgas figure.



# Extensive Natural Gas Storage Footprint Provides Valuable Supply for Variable Demand

KM working storage capacity  
**~702 bcf**  
 Evaluating multiple brownfield expansion opportunities

- ① NGPL**  
 Highly contracted storage key for seasonal & peak day power, LDC & industrial demand  
*288 bcf, cost-based rates*
- ② Texas Intrastates**  
 Highly responsive storage critical to serving LNG facilities & during extreme weather events  
*138 bcf, market-based rates*
- ③ TGP & Stagecoach**  
 Provide significant seasonal & peak day deliverability to Northeast markets  
*116 bcf; 41 bcf is market-based rates*
- ④ SNG**  
 Fully contracted with significant LDC & power demand  
*66 bcf, cost-based rates*
- ⑤ EPNG**  
 Highly utilized & fully contracted storage serves CA & AZ power demand  
*50 bcf, mostly cost-based rates*
- ⑥ CIG**  
 Fully contracted for LDC & power demand along the Colorado Front Range  
*44 bcf, cost-based rates*

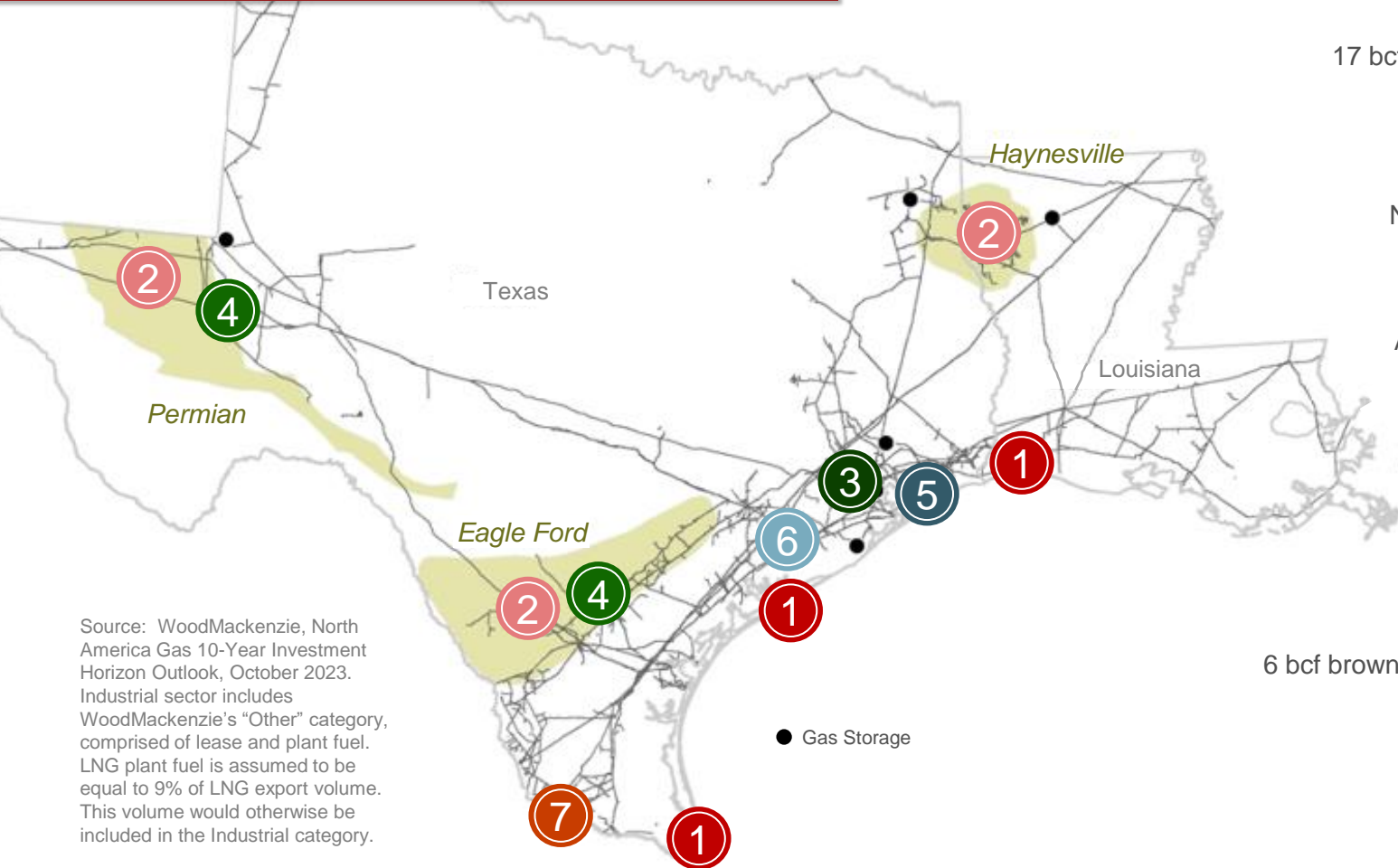


Opportunity to capture greater storage values as demand grows, particularly in areas with market-based rates

# Spotlight on Texas and Louisiana Natural Gas Market

>95% of Demand Growth is Expected to Occur in Texas & Louisiana, Driven by Exports & Industrial

~70% of our \$2.2bn Natural Gas backlog is located in Texas & Louisiana



Source: WoodMackenzie, North America Gas 10-Year Investment Horizon Outlook, October 2023. 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.

## LNG Exports ①

Gulf Coast feedgas demand set to grow 16 bcf by 2030  
Extensive network positioned to increase deliveries & offer supply diversification

## Supply Growth ②

17 bcf of growth out of the Permian, Haynesville, and Eagle Ford by 2030  
World-class basins, key to serving global natural gas demand

## Power Demand ③

Natural gas needed to backstop growing renewable power generation

## Pipeline Takeaway ④

Additional Permian & Eagle Ford egress needed as production grows

## Industrial Demand ⑤

+3 bcf of primarily Gulf Coast demand by 2030  
Network directly connects to industrial facilities along the Gulf Coast

## Storage Opportunities ⑥

Increased need for storage to serve growing intermittent demand  
6 bcf brownfield Markham storage expansion; evaluating additional opportunities

## Mexico Exports ⑦

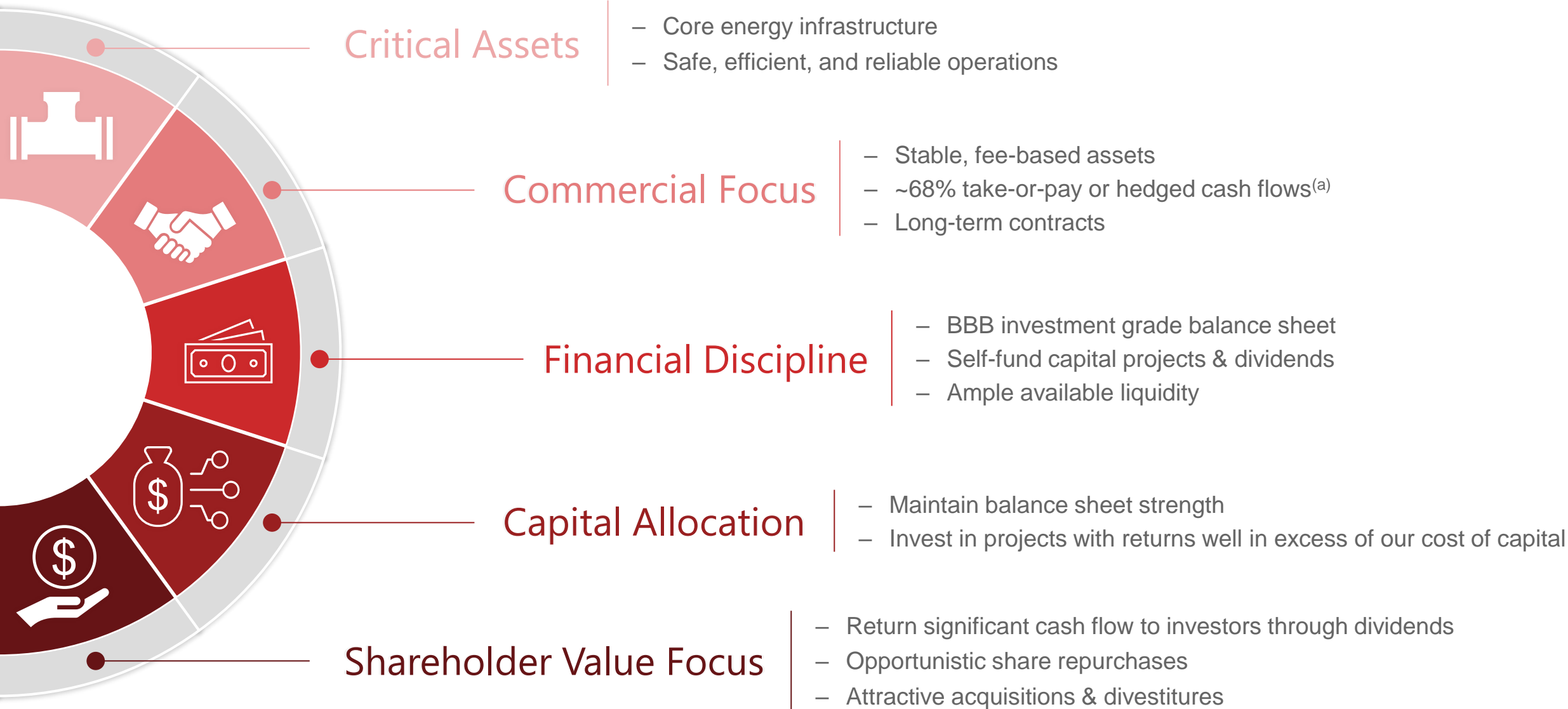
Texas exports to Mexico forecasted to grow 2 bcf by 2030  
Expect our deliveries to Mexico to grow over time

# STRATEGY & EXECUTION

*Tom Martin*

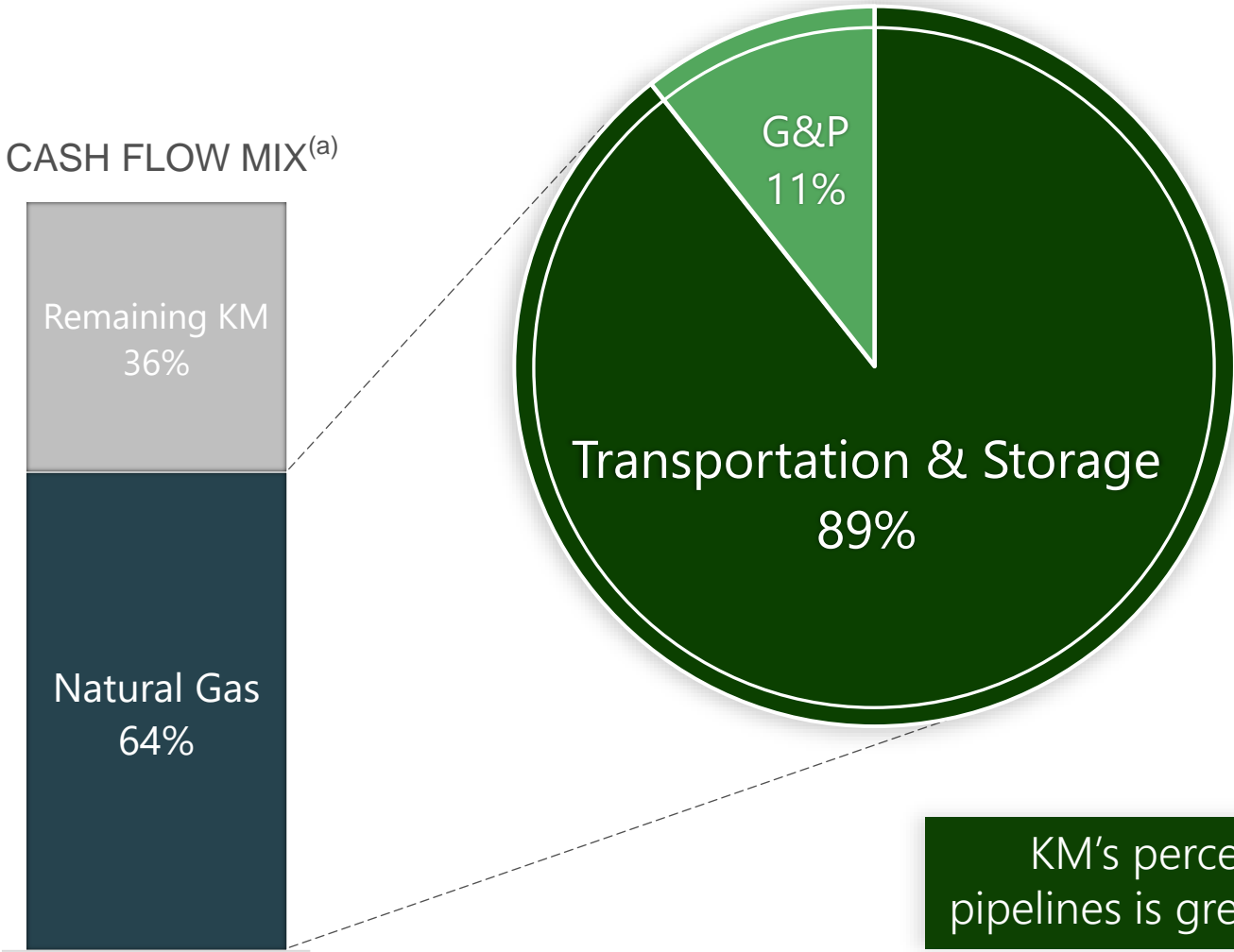


# Strategic Approach



a) Based on 2024 budgeted Total Adjusted Segment EBDA, which is a non-GAAP measure. See Non-GAAP Financial Measures & Reconciliations.

# High-Quality, Natural Gas Focused Cash Flows



## Natural Gas Transportation & Storage

- 57% of 2024B Total Adj. Segment EBDA
- 89% take-or-pay cash flows<sup>(a)</sup>
- Average remaining contract life:
  - ~6 years for transportation
  - ~4 years for storage

KM's percent cash flow contribution from long-haul natural gas pipelines is greater than any other large U.S. midstream company<sup>(b)</sup>

a) Based on 2024 budgeted Total Adjusted Segment EBDA, which is a non-GAAP measure. See Non-GAAP Financial Measures & Reconciliations.  
b) Includes U.S. midstream companies with market capitalizations greater than \$10 billion.

# \$3.0bn Committed Growth Capital Project Backlog as of 12/31/2023

Expect 53% of Backlog Capital In Service in 2024, 36% in 2025, and 11% Beyond

\$ million	TOTAL	LOWER CARBON	
Natural Gas (excluding G&P)	\$1,613	\$1,613	96% for end-use, 2% supply-push, 2% CCS
Refined Products (excluding G&P)	158	85	Renewable feedstocks and fuels projects
Energy Transition Ventures	84	84	92% RNG facilities; 8% CCS project
<b>Subtotal</b>	<b>\$1,854</b>	<b>\$1,782</b>	Contracted, stable cash flows, minimal direct commodity exposure
<b>EBITDA build multiple</b>	<b>~4.6x</b>	<b>~4.7x</b>	
Gathering & processing	\$585	\$539	Volume-based cash flows; 92% natural gas, 8% crude oil
EOR	538	–	Commodity price & volume-based cash flows
<b>Total backlog</b>	<b>\$2,978</b>	<b>\$2,322</b>	

Lower carbon investments ~78% of backlog

Expect annual growth capital spend of ~\$1-2 billion going forward; high end of range in the near-term

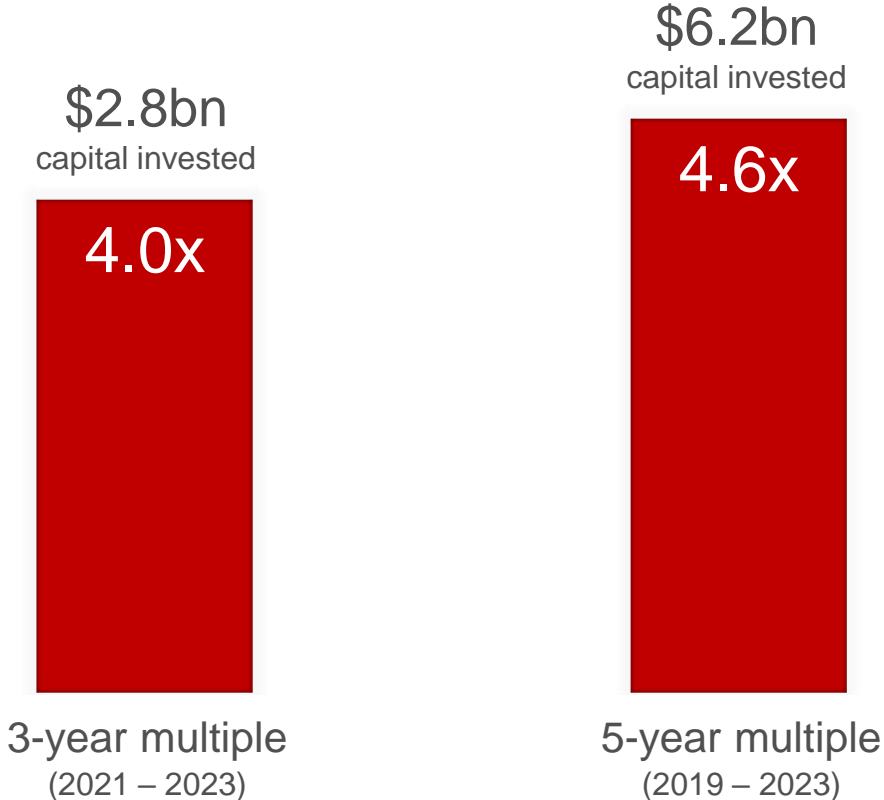
Note: The EBITDA build multiple reflects KM share of estimated capital divided by estimated Project EBITDA (a non-GAAP measure). See Non-GAAP Financial Measures & Reconciliations. Figures may not sum due to rounding. Lower carbon includes investments in conventional natural gas, renewable diesel, biofuel feedstocks, RNG, and CCS. Refined Products includes projects in our Products and Terminals segments.

# Successfully Achieving Attractive Build Multiples

Established Track Record of Leveraging Our Footprint & Project Management Expertise

## INVESTMENT MULTIPLES ACHIEVED OVER TIME

Total Capital Invested / Year 2 Project EBITDA<sup>(a)</sup>



Note: Project EBITDA is a non-GAAP measure. See Non-GAAP Financial Measures & Reconciliations.  
a) Multiple reflects KM share of invested capital divided by Project EBITDA generated in its second full year of operation. Includes G&P projects. Excludes CO<sub>2</sub> EOR projects.

## Competitive Advantages

- Expansive asset base — ability to leverage or repurpose steel already in the ground
- Connected to all major supply sources
- Connected to all major demand centers — irreplicable final mile due to expense or permitting
- Funding investments with operating cash flows

Expansive footprint creates opportunities for differentiated returns

# Robust Macro Environment Gives Confidence in the High End of ~\$1–\$2 Billion of Annual Growth Spend Over the Next Few Years



## NATURAL GAS

- LNG Exports (Gulf Coast & West Coast)
- Supply short Southeast markets
- Exports to Mexico (Gulf Coast & West Coast)
- Storage
- Industrials
- Power
- Permian egress



## REFINED PRODUCTS

- Infrastructure for renewable feedstocks & fuels

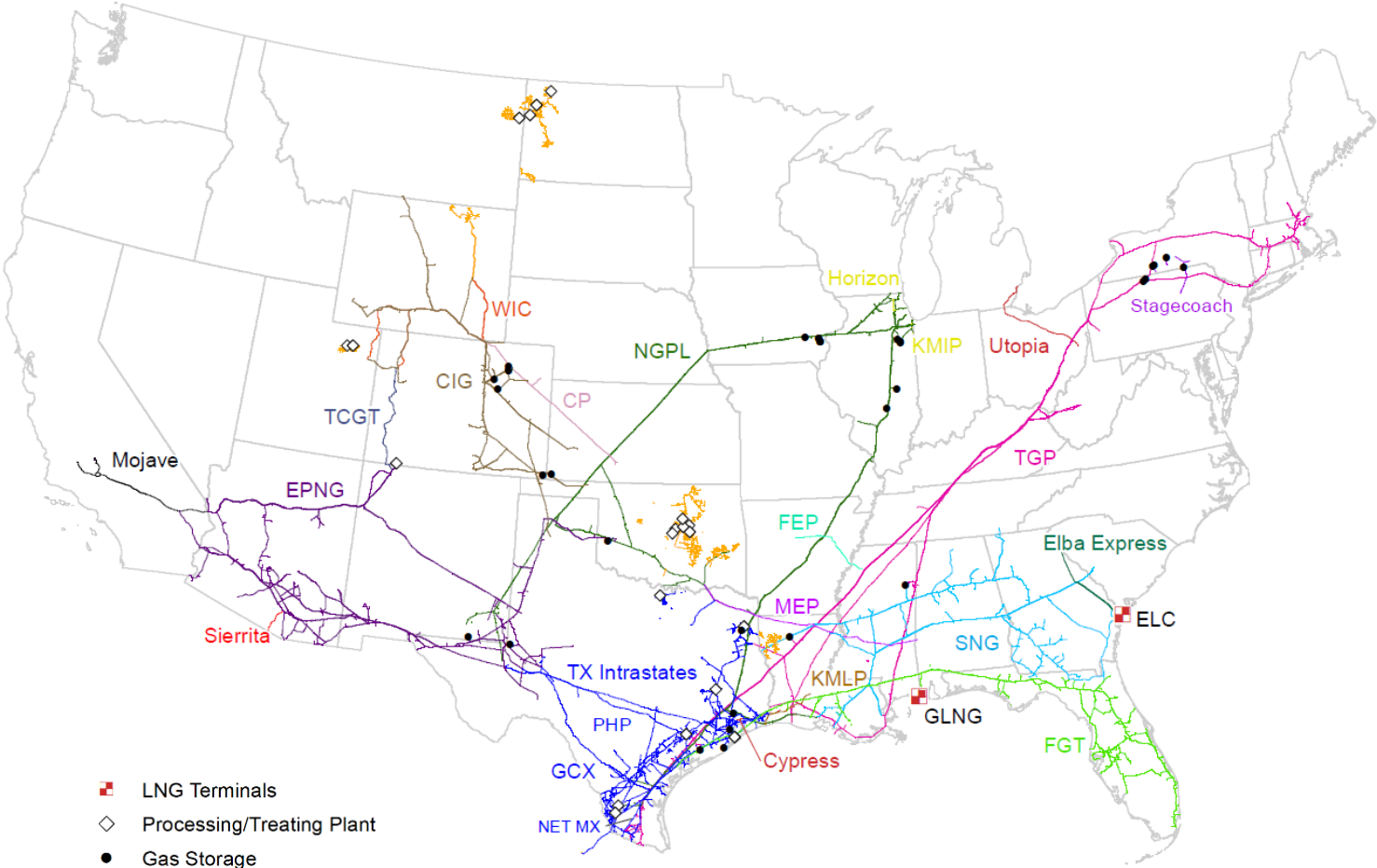


## ETV GROUP

- RNG
- CCS, near & outside current CO<sub>2</sub> footprint

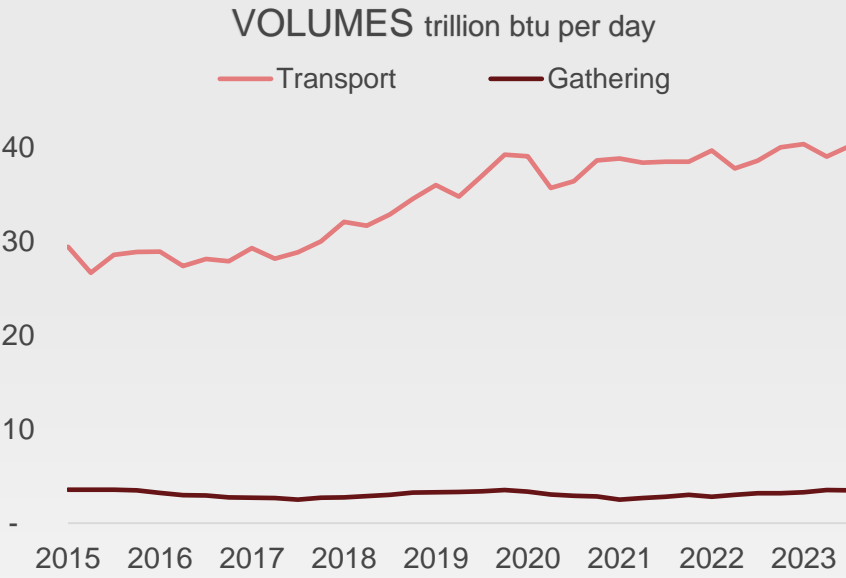
# Natural Gas Segment Overview

Connecting Key Natural Gas Resources with Major Demand Centers



## ASSET SUMMARY

Natural gas pipelines:	~70,000 miles
NGL pipelines:	~1,200 miles
Natural gas transported (U.S. consumption & exports)	~40%
Working gas storage capacity:	702 bcf



Largest natural gas transmission network in the U.S.

# \$1.815bn Acquisition of NEP's South Texas Natural Gas Pipelines

462 Miles of Primarily Long-Haul Natural Gas Pipelines with 4.9 bcfd of Transport Capacity

## KMI acquired NEP's South Texas assets, STX Midstream

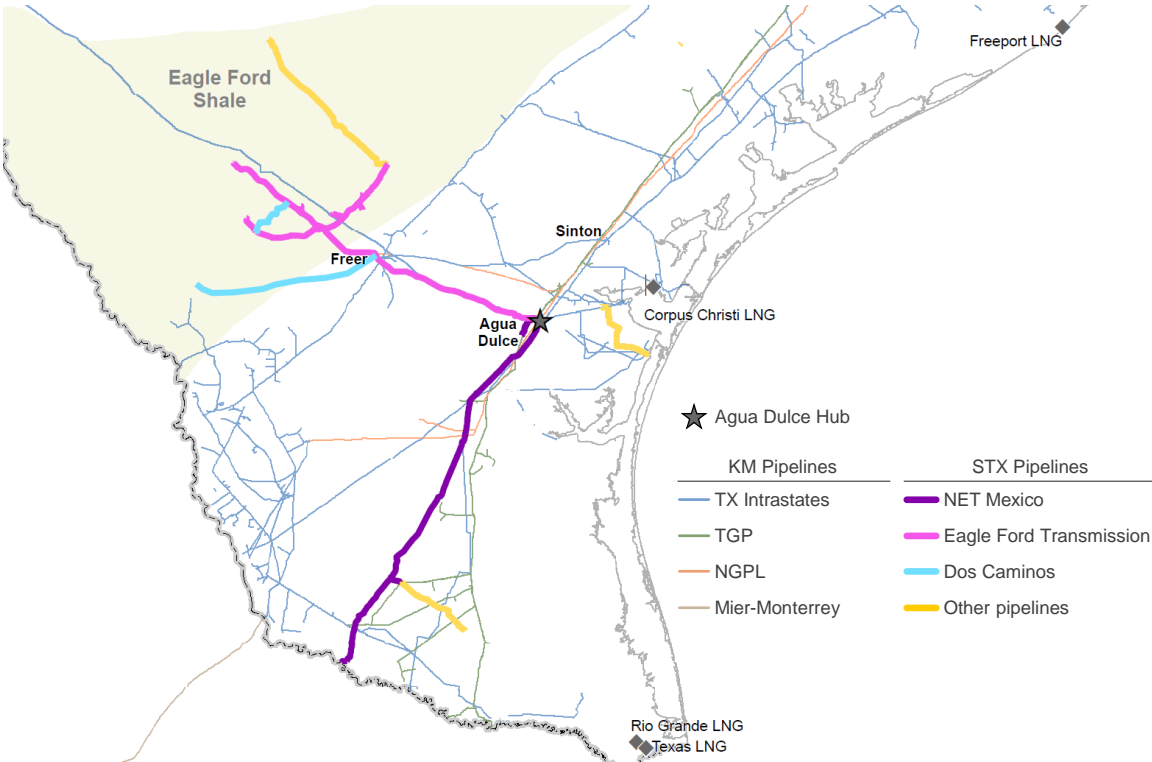
- ~8.6x 2024 EBITDA; 7.0-7.5x long-term including commercial synergies<sup>(a)</sup>
- Immediately accretive to DCF/sh and strongly free cash flow positive
- Increases Net Debt-to-EBITDA by ~0.1x<sup>(b)</sup>

## Intrastate assets complementary to KMI's existing South TX footprint

- Supports strategy to serve growing LNG, industrial, Mexican export, and power generation demand markets on the U.S. Gulf Coast
- Integrates with our existing intrastate/interstate footprint
  - Connections with multiple KMI assets including TX Intrastates, TGP and NGPL
  - Extends our direct connectivity in the lean area of the Eagle Ford basin
    - Opportunity to blend with supply from other KM assets to offer low-nitrogen natural gas desirable for LNG
  - Commercial synergies with existing and potential projects

## Stable fee-based infrastructure

- Fixed fee business; ~75% take-or-pay
- Average contract term >8 years; favorable renewal outlook
- Primarily supported by investment grade, direct end-use demand customers including Pemex, electric generation, and LDCs



## STX Midstream natural gas pipeline assets:

- **NET Mexico** (90% interest, operator); 120 miles, 2.2 bcfd capacity; connects Agua Dulce hub to U.S./MX border
- **Eagle Ford Transmission** (100% interest); 158 miles, 1.1 bcfd capacity; connects Eagle Ford to Agua Dulce hub
- **Dos Caminos** (50% interest); 75 miles, 1.2 bcfd capacity; delivers gas from Eagle Ford producers into EFM and TX Intrastates
- **5 other assets** (100% interest); 109 miles, 0.5 bcfd capacity; principally supplying demand-pull customers like power plants and LDCs

a) Based on KMI's financial projections.

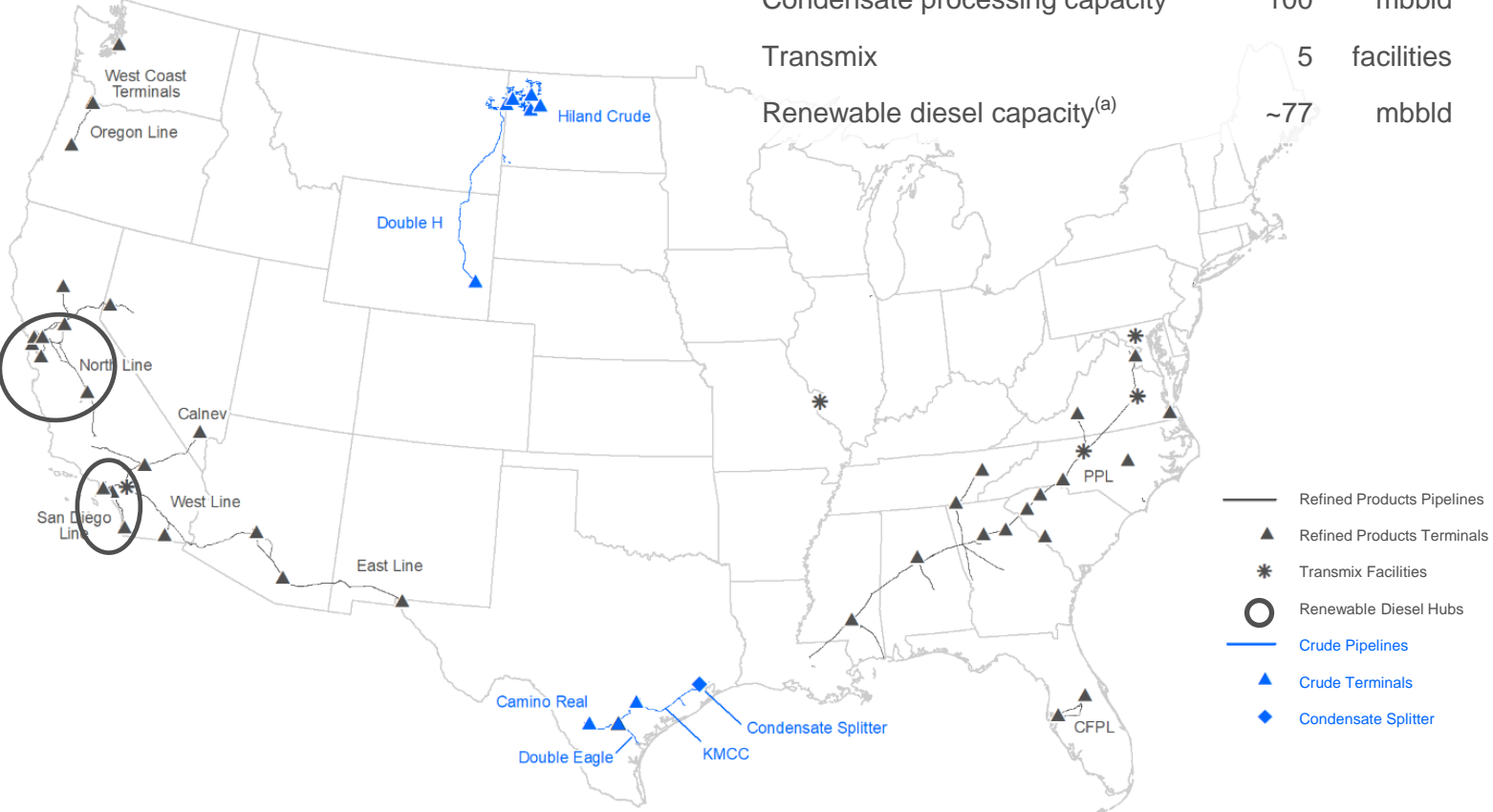
b) With full-year EBITDA contribution from acquired assets. Based on longer-term funding plans, expect transaction to be neutral to KMI's balance sheet.

# Products Segment Overview

Strategic Footprint Supplying a Diverse Mix of Feedstock & Finished Products  
 Critical to Refining & Transportation Sectors

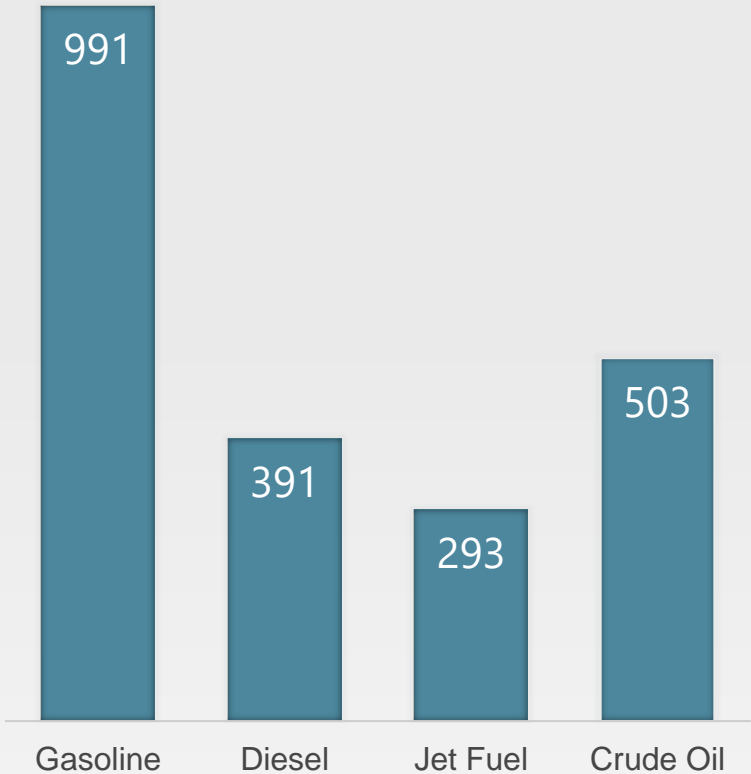
## ASSET SUMMARY

Pipelines:	~9,500 miles	Terminals:	65 terminals
2024 budgeted throughput <sup>(a)</sup>	~2.2 mmbld	Tank capacity	~56 mmbls
		Condensate processing capacity	100 mbbld
		Transmix	5 facilities
		Renewable diesel capacity <sup>(a)</sup>	~77 mbbld



a) Includes RD hub capacity in Northern and Southern California, and Carson truck rack capacity.  
 b) Kinder Morgan volumes include SFPP, CALNEV, Central Florida, PPL (KM share), KMCC, Camino Real, Double Eagle (KM share), Double H & Hiland Crude Gathering; Gasoline volumes include ethanol.

2024B DELIVERY VOLUMES<sup>(b)</sup> mbbld

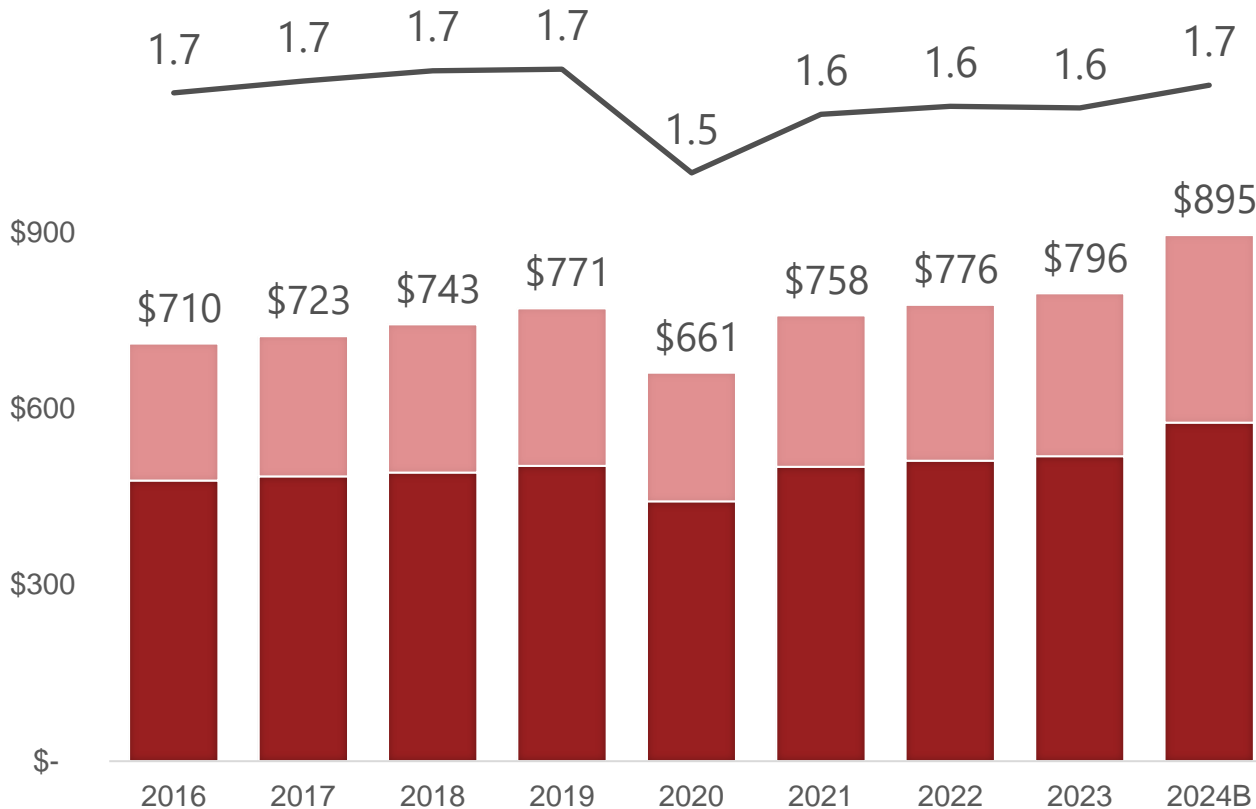


# Refined Products Pipes a Steady Contributor

Fee-Based With Stable Volumes and Cash Flow Over the Long-Term

REFINED PRODUCTS ADJUSTED SEGMENT EBDA BY REGION<sup>(a)</sup> AND TOTAL VOLUME<sup>(b)</sup>

West Coast (\$mm) Southeast (\$mm) Volume (mmbbl/d)



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

a) Contributions to Products Pipelines Adjusted Segment EBDA are from SFPP, CALNEV, West Coast Terminals, Central Florida, Transmix, PPL (KM share) & Southeast Terminals.

b) Kinder Morgan volumes include SFPP, CALNEV, Central Florida & PPL (KM share).

## Advantaged Network

- Offers unmatched connectivity between major refining centers & key demand markets
- Renewable diesel projects help maintain West Coast diesel market share on pipelines and enable expanded rack blending opportunities at the terminals
- Attractive, capital efficient blending opportunities
- FERC rate escalator on refined products pipes helps protect earnings against potential volume declines and/or cost inflation

ADJ. SEGMENT EBDA CAGR

2.9%

VOLUME CAGR

> 0.1%

# Pivoting Product Segment's West Coast Assets to Handle Additional Renewable Diesel Volumes

CURRENT ASSETS & FUTURE OPPORTUNITIES	
<p><b>Southern California Hub</b> (RD by pipeline)</p>	<ul style="list-style-type: none"> <li>- Providing ~18 mbbl/d RD capacity at truck rack between Colton &amp; Mission Valley</li> <li>- Increasing biodiesel blend capabilities to 20% at Colton</li> </ul>
<p><b>Carson</b> (Port of LA)</p>	<ul style="list-style-type: none"> <li>- Providing ~20 mbbl/d RD capacity at truck rack</li> <li>- Converting ~750 mbbl storage capacity to RD</li> </ul>
<p><b>Northern California Hub</b> (RD by pipeline)</p>	<ul style="list-style-type: none"> <li>- Providing ~39 mbbl/d RD capacity at truck rack between Fresno, San Jose, and Bradshaw</li> </ul>
<p><b>Richmond</b> (Bay Area)</p>	<ul style="list-style-type: none"> <li>- Converting ~50 mbbl storage capacity to RD with access to the rack</li> </ul>
<p><b>Washington &amp; Oregon</b></p>	<ul style="list-style-type: none"> <li>- Evaluating potential conversion opportunities to handle RD</li> </ul>

ability to move  
**~57 mbbl/d**  
of RD via pipeline  
at our hubs

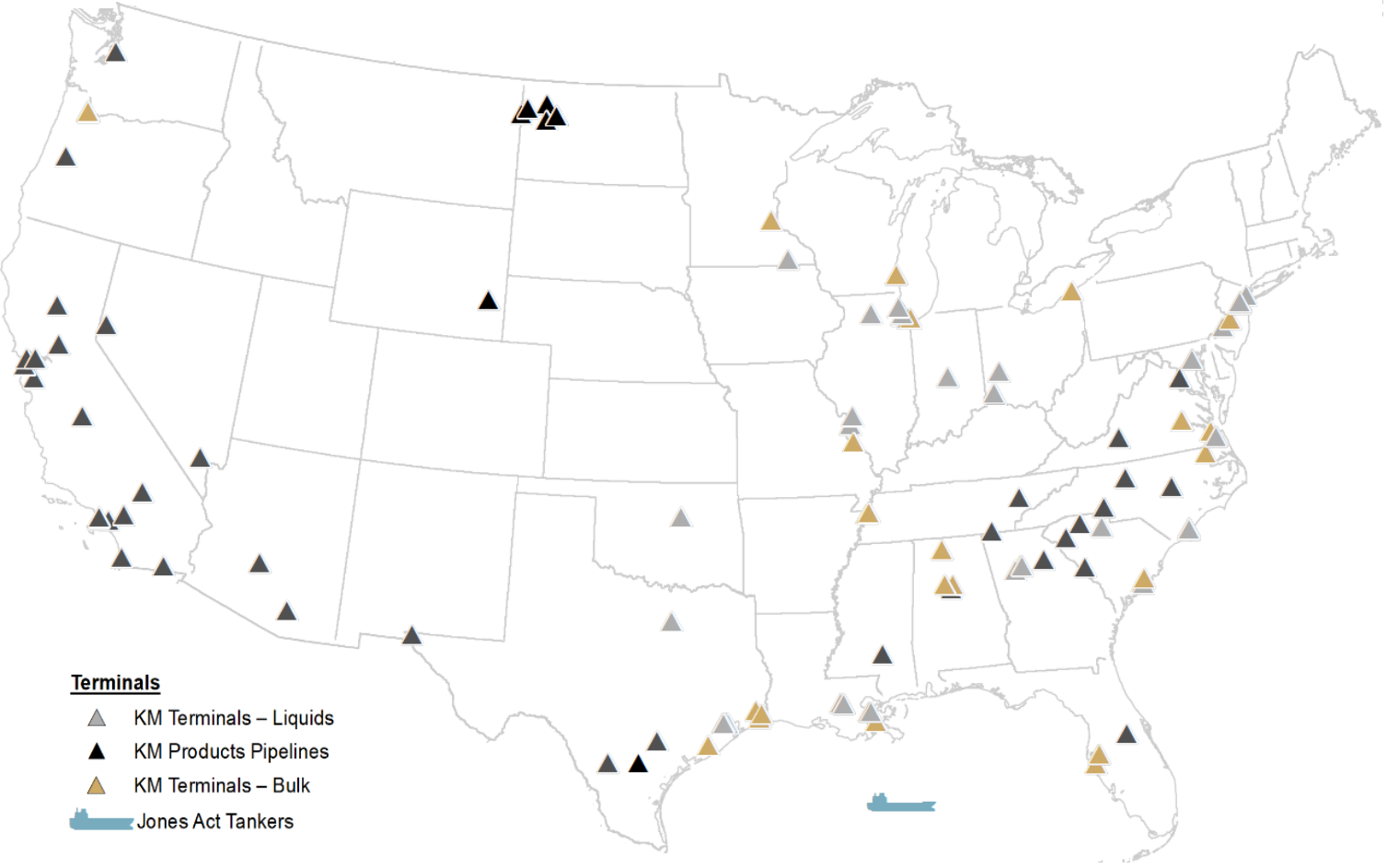


First company to transport RD via pipeline to market in the U.S.

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	27	
Terminals segment – Liquids	47	79
Products segment	65	56
<b>Total Terminals</b>	<b>139</b>	<b>135</b>
<b>Jones Act:</b>	<b>16 tankers</b>	

Nationwide footprint focused on refined products, renewables & chemicals

Earnings driven by long-term contractual use of our assets

Infrastructure critical to our customers & their business

# Liquid Hubs: Strategically Located to Serve Key Markets

**Houston Ship Channel** 9 terminals providing ~43 million barrels of capacity<sup>(a)</sup>

- Serves the world’s most competitive supply of refined products & petrochemicals

**New York Harbor** 5 terminals providing ~14 million barrels of capacity

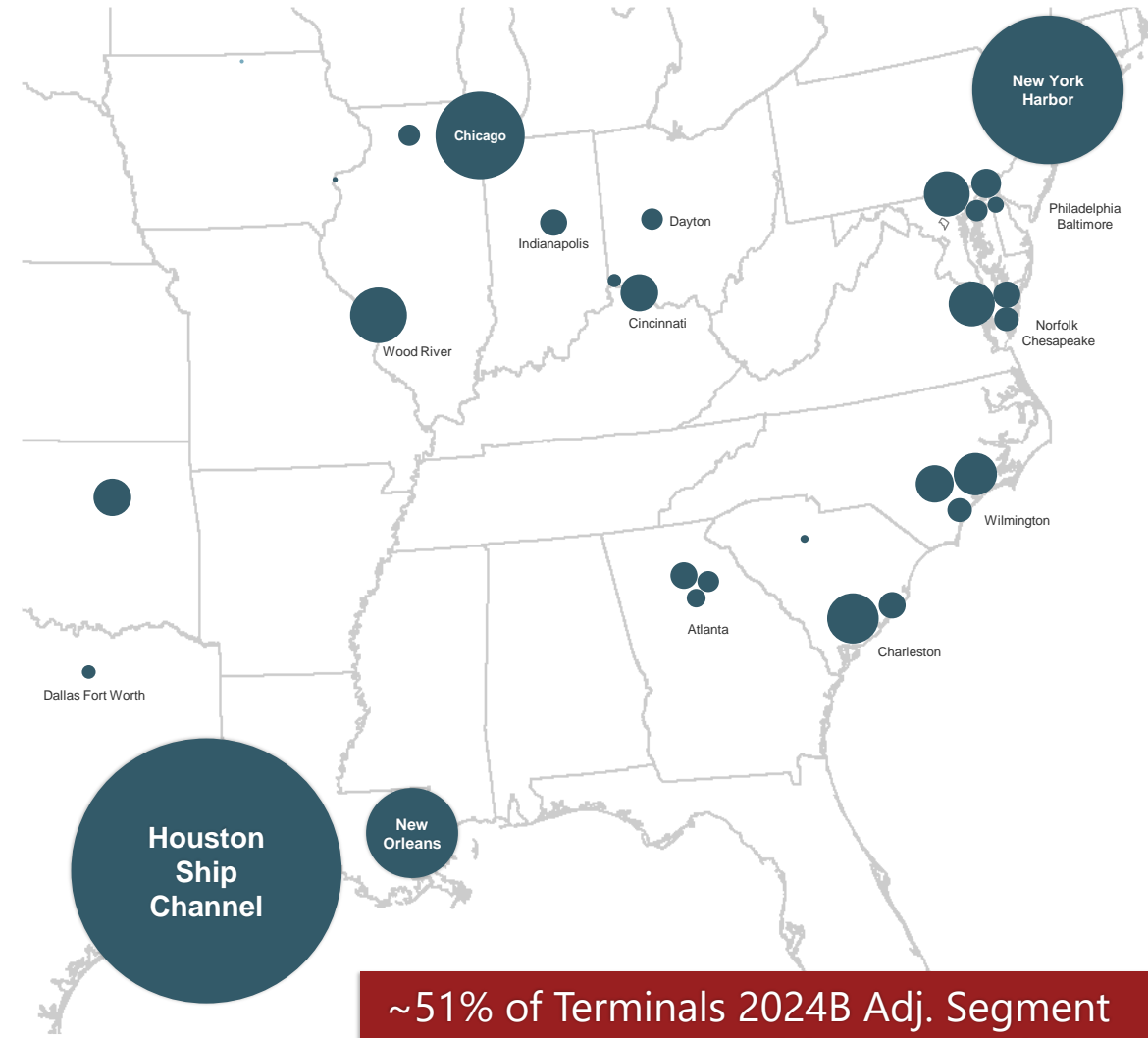
- Serves as the world’s largest & most liquid refined product clearinghouse

**New Orleans** 6 terminals providing ~5 million barrels of capacity

- Serves growing renewable & chemical markets along the Mississippi River

**Chicago** 4 terminals providing ~5 million barrels of capacity

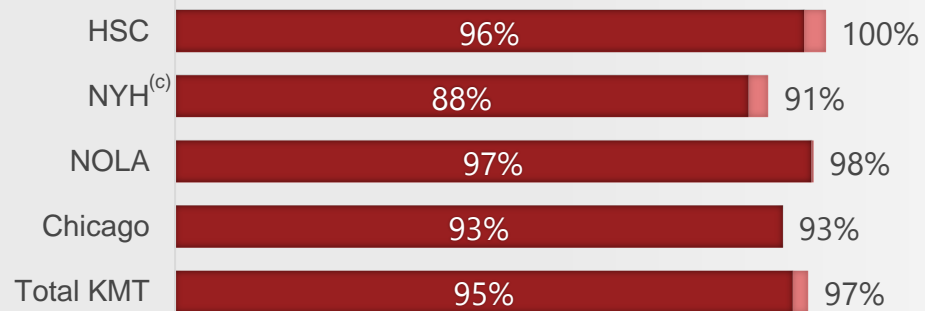
- Serves as the nation’s ethanol clearinghouse, pricing & trading hub



**~51% of Terminals 2024B Adj. Segment EBDA generated from Liquid hubs**

## 2024B LIQUIDS UTILIZATION<sup>(b)</sup>

■ Leased ■ API



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

a) Houston Ship Channel includes tankage associated with Products segment splitter at Galena Park; capacities represented on a gross basis.

b) 2024B liquids utilization reflects ratio of our tankage capacity in-service to total liquids leasable capacity; API reflects tankage temporarily unavailable for lease due to scheduled inspection and repair.

c) Principal asset (Carteret, NJ): 97% leased; 99% adjusted for API's.

# Industry-Leading Renewable Feedstock Storage & Logistics Offering

Leveraging Existing Assets to Grow Our Renewable Feedstock Capabilities



>1,600 mbb of capacity leased for renewable feedstock storage across our network<sup>(a)</sup>

a) Includes tanks under construction

## One of the largest handlers of renewable feedstocks

- Utilizing existing assets towards capital-efficient, attractive-returning projects supporting the growing renewable fuels market
- Handle renewable feedstocks & fuels at several locations across our network
- Investing ~\$135mm to expand our Lower Mississippi River Hub (New Orleans)
- Advantaged network provides customers with flexible transportation options via rail, truck, vessel, and pipeline

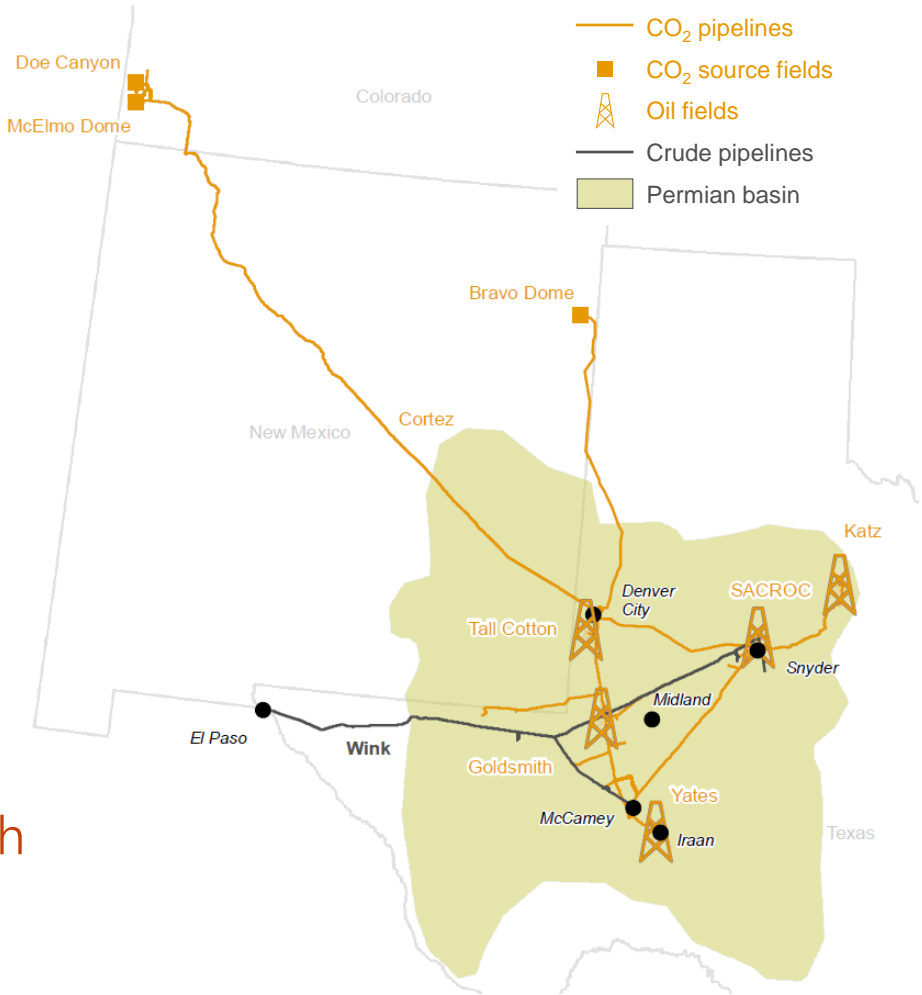
# CO<sub>2</sub> Segment Overview

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

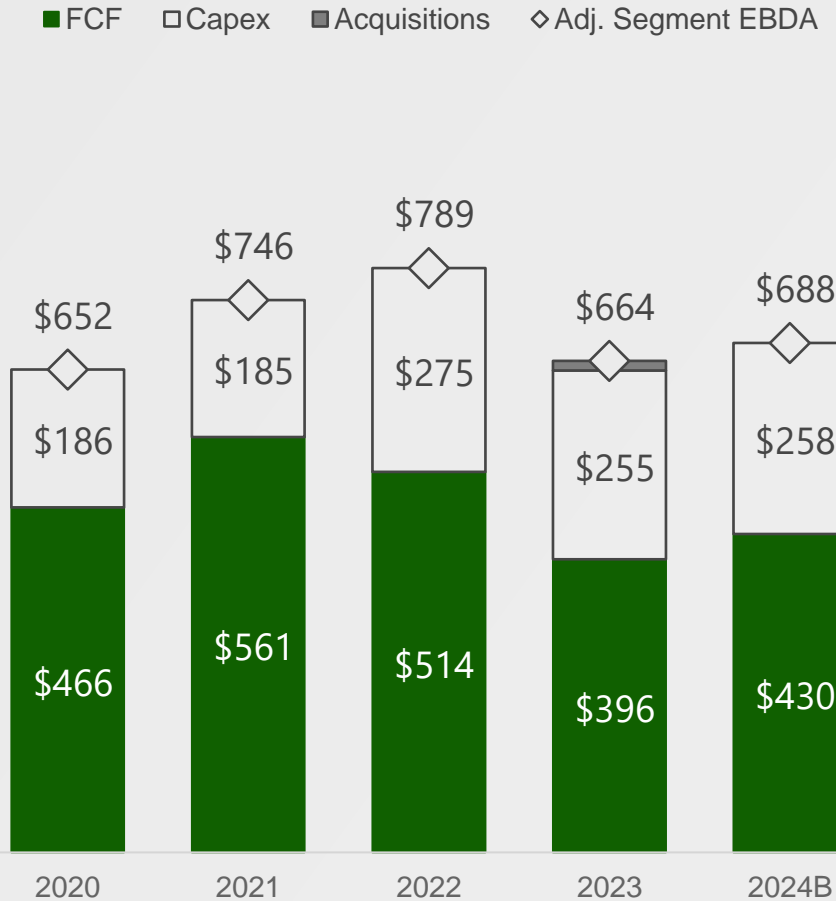
Interest in 5 oil fields with 9.3 billion barrels of Original Oil In Place

Interest in 3 CO<sub>2</sub> fields with 37 tcf of Original Gas In Place

~1,500 miles of CO<sub>2</sub> pipelines with capacity to move up to 1.5 bcfd



CO<sub>2</sub> EOR & TRANSPORT FREE CASH FLOW  
\$ millions



Note: CO<sub>2</sub> EOR & Transport FCF and Adjusted Segment EBDA are non-GAAP measures. See non-GAAP Financial Measures & Reconciliations. SACROC includes Diamond M acreage.

# Energy Transition Ventures (ETV) Group

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



Established a growing RNG platform and expanding opportunities in the CCS space

## Renewable Natural Gas

- Brought 3 facilities online in 2023 and expect a 4<sup>th</sup> in service by 2H 2024
- Up to 6.4 bcf<sup>(a)</sup> of RNG production capacity once all facilities are online
- Expect first full-year Project EBITDA multiple of ~6x based on cumulative investment once all facilities are in service

## Carbon Capture and Storage

- Red Cedar project continues to progress, with a targeted in-service of Q4 2024
- Pursuing additional opportunities across the CCS value chain

Note: Project EBITDA is a non-GAAP measure. See Non-GAAP Financial Measures and Reconciliations.  
a) Annual capacity at KM share.

# How Kinder Morgan Drives Shareholder Value



# FINANCIAL OVERVIEW

*David Michels*



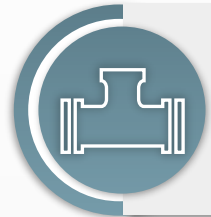
## Robust and Secure Cash Flows

*Natural gas focused, long-term, take-or-pay cash flows*



## Balance Sheet Strength

*Capacity provides value and flexibility*



## High Threshold for Capital Allocation

*Investing in high-returning projects well above our cost of capital*



## Significant Free Cash Flow Generation

*Enables additional opportunities to increase shareholder value*



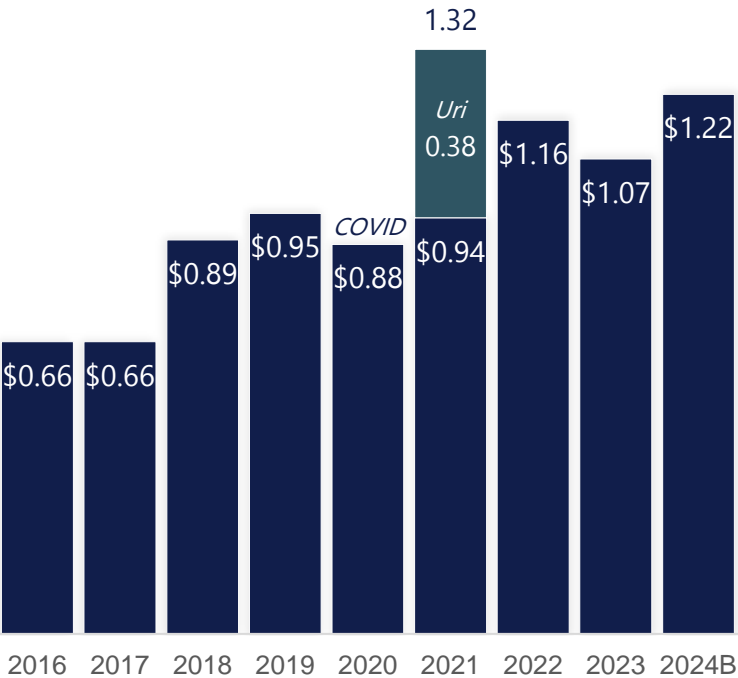
## Committed to Shareholder Value

*Well-covered dividends and opportunistic share buybacks*

# Growing Earnings, Reducing Leverage, and Returning Meaningful Value to Shareholders

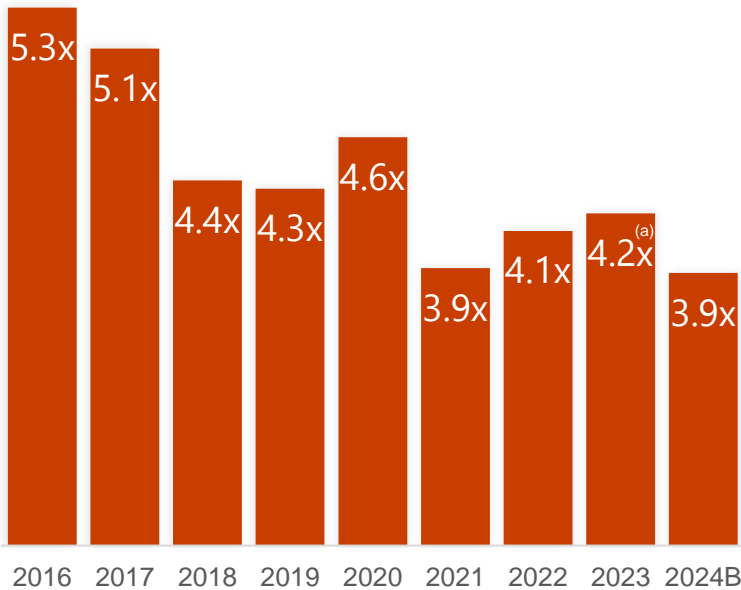
ADJUSTED EPS

8% CAGR



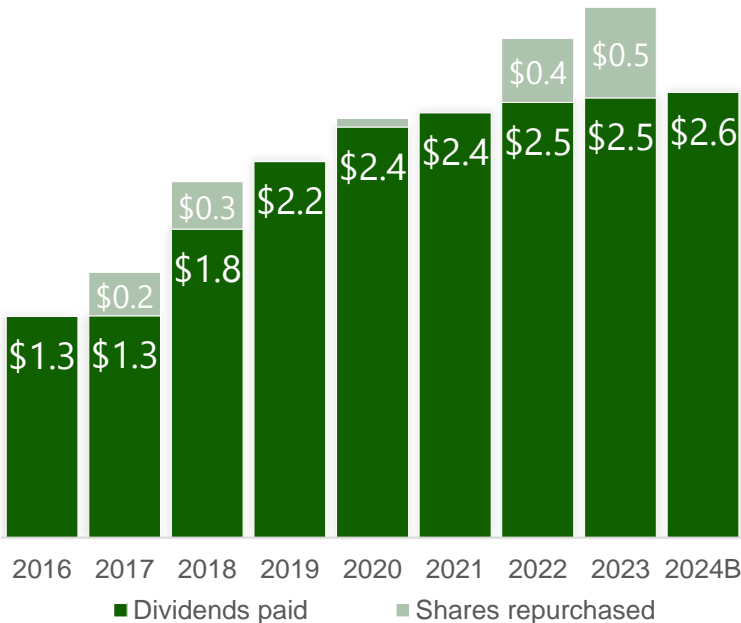
NET DEBT / ADJUSTED EBITDA

26% decrease in leverage



DIVIDENDS PAID & SHARES REPURCHASED<sup>(b)</sup> (\$ billion)

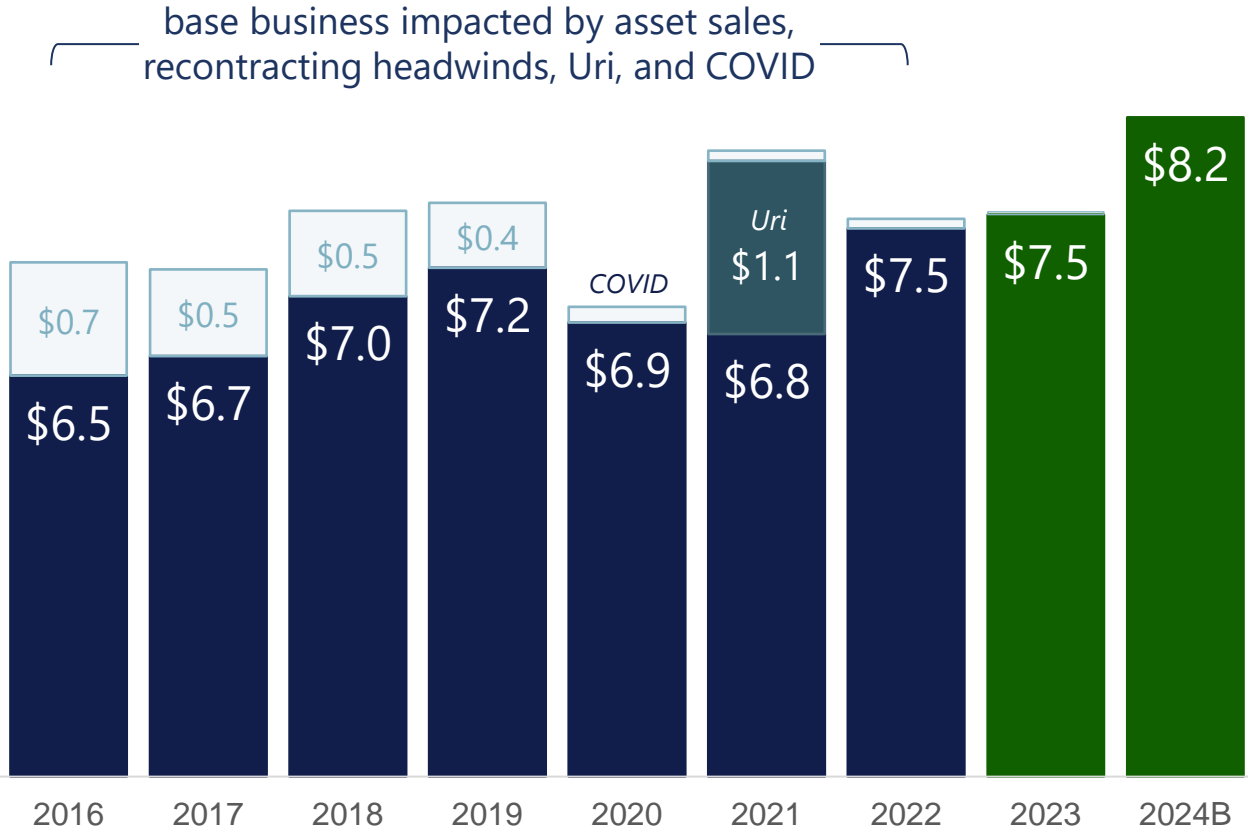
\$20.3 billion returned to shareholders



Note: Adjusted EPS, Adjusted EBITDA and Net Debt are non-GAAP measures. See Non-GAAP Financial Measures & Reconciliations. Individual years may not sum to total due to rounding.  
 a) Includes debt associated with STX Midstream acquisition, which closed on 12/28/2023. Year-end 2023 leverage would have been 4.1x with a full-year EBITDA contribution from the acquired assets.  
 b) No share repurchases assumed in 2024 budget. 2016, 2017, and 2018 include dividends paid to preferred shareholders.

# Base Business Stability Provides Opportunity for Growth

ADJUSTED EBITDA \$billion



□ Adj. EBITDA generated from assets divested 2016 - 2023

base business impacted by asset sales, recontracting headwinds, Uri, and COVID

2016 - 2022

- ~\$700 million in divested EBITDA from asset sales related to Canadian assets, SNG, NGPL, and Elba
- Large contract rollovers associated with supply push pipelines like MEP, FEP, and Ruby
- COVID impact in 2020-2021 & Uri impact in 2021

2023 - 2024+

- Reached an inflection point where large recontracting headwinds are behind us and base business is more stable
- Existing natural gas network continues to fill up, leading to higher values for contract renewals on average
- Benefit from rate escalators in Products and Terminals
- ~\$3 billion of committed projects at <5x EBITDA build multiple

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

# 2024 Budget Highlights

Adjusted  
EPS



\$1.22

~14% increase  
vs. 2023

Adjusted  
EBITDA



\$8.2bn

~8% increase  
vs. 2023

DCF / Share



\$2.26

~8% increase  
vs. 2023

Net Debt /  
Adjusted EBITDA



3.9x

0.3x decrease  
vs. year-end 2023

Cash  
Returns



\$2.6bn

Dividends expected  
in 2024

# 2024 Guidance Reconciliation

Key metrics	Preliminary Budget <sup>(a)</sup> (Dec. 4, 2023)	Final Budget <sup>(a)</sup> (incl. STX acquisition)
Adjusted EPS	\$1.21	\$1.22
Distributable Cash Flow	\$4.95 billion	\$5.05 billion
Distributable Cash Flow (DCF) / Share	\$2.21	\$2.26

\$82/bbl WTI crude sensitivity for final 2024 Budget: ~\$8.0mm per \$1/bbl change<sup>(b)</sup>

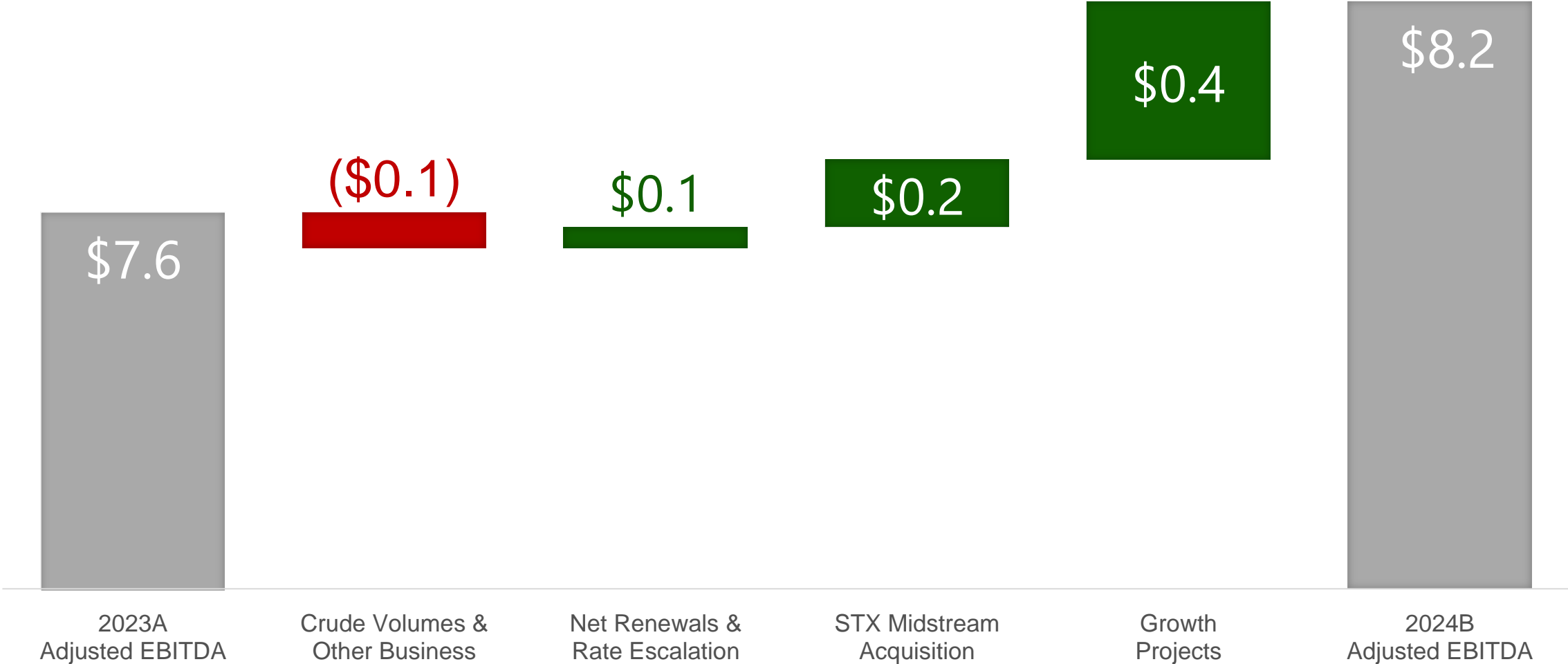
Note: Adjusted EPS and DCF are non-GAAP measures. See Non-GAAP Financial Measures & Reconciliations.

a) Commodity price forecast consistent with the forward curve at the time of the budget process.

b) For a full list of sensitivities, see the Corporate Items section in the appendix.

# Steady Base Business & Growth From Investments

\$ Billions



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

# 2024B Adjusted EPS & Distributable Cash Flow (DCF)

In Millions, Except Per Share

	2024	2023	Change	
	Budget	Actual	\$	%
Net income attributable to KMI	\$ 2,726	\$ 2,391	\$ 335	14%
Net income Allocated to participating securities <sup>(a)</sup>	(18)	(14)	(4)	(29%)
Net income attributable to Common Stock	2,708	2,377	331	14%
Total Certain Items <sup>(b)</sup>	-	19	(19)	(100%)
<b>Adjusted Net income attributable to Common Stock</b>	<b>\$ 2,708</b>	<b>\$ 2,396</b>	<b>\$ 312</b>	<b>13%</b>
<hr/>				
Weighted average shares outstanding	2,221	2,234	(13)	(1%)
EPS	\$ 1.22	\$ 1.06	\$ 0.16	15%
Adjusted EPS	\$ 1.22	\$ 1.07	\$ 0.15	14%
<hr/>				
DCF	\$ 5,045	\$ 4,715	\$ 330	7%
Weighted average shares outstanding for dividends <sup>(c)</sup>	2,236	2,247	(11)	(0%)
DCF per share	\$ 2.26	\$ 2.10	\$ 0.16	8%
Expected/Declared dividend per share	\$ 1.15	\$ 1.13	\$ 0.02	2%

## 2% dividend increase with even more cash flow coverage

Note: Adjusted Net Income attributable to Common Stock, Distributable Cash Flow (DCF), in aggregate and per share, and Adjusted EPS are non-GAAP financial measures. See Non-GAAP Financial Measures and Reconciliations.

a) Net income allocated to participating securities (this only includes restricted stock for the periods shown) 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) See table included in "Non-GAAP Financial Measures—Certain Items."

c) Includes 15 million and 13 million average unvested restricted shares that participate in dividends in 2024 and 2023, respectively.

# 2024B Adjusted Segment EBDA and Adjusted EBITDA

\$ in Millions

	2024	2023	Change	
	Budget	Actual	\$	%
Natural Gas Pipelines Adjusted Segment EBDA	\$ 5,524	\$ 5,160	\$ 364	7%
Products Pipelines Adjusted Segment EBDA	1,218	1,128	90	8%
Terminals Adjusted Segment EBDA	1,054	1,040	14	1%
CO <sub>2</sub> Adjusted Segment EBDA	849	693	156	23%
<b>Total Adjusted Segment EBDA</b>	<b>8,645</b>	<b>8,021</b>	<b>624</b>	<b>8%</b>
G&A and corporate charges <sup>(a)</sup>	(736)	(714)	(22)	(3%)
JV DD&A and income tax expense <sup>(a)(b)</sup>	353	349	4	1%
Net income attributable to NCI <sup>(a)</sup>	(106)	(95)	(11)	(12%)
<b>Adjusted EBITDA</b>	<b>8,156</b>	<b>7,561</b>	<b>595</b>	<b>8%</b>
Interest, net <sup>(a)</sup>	(1,881)	(1,804)	(77)	(4%)
Cash taxes for DCF <sup>(c)</sup>	(125)	(87)	(38)	(44%)
Sustaining capital expenditures for DCF <sup>(d)</sup>	(1,172)	(1,022)	(150)	(15%)
Other items <sup>(e)</sup>	67	67	-	-
<b>DCF</b>	<b>\$ 5,045</b>	<b>\$ 4,715</b>	<b>330</b>	<b>7%</b>

## Key Drivers

Natural Gas	<ul style="list-style-type: none"> <li>– Contributions from expansion projects</li> <li>– Acquisition of STX Midstream assets</li> <li>– Unfavorable re-contracting impacts (STX Copano &amp; MEP)</li> </ul>
Products	<ul style="list-style-type: none"> <li>– Favorable rate escalations (FERC Index, Other)</li> <li>– Contributions from expansion projects</li> </ul>
Terminals	<ul style="list-style-type: none"> <li>– Contributions from expansion projects</li> <li>– Favorable contract escalations (CPI/PPI)</li> <li>– Unfavorable contract renewals</li> </ul>
CO <sub>2</sub>	<ul style="list-style-type: none"> <li>– Contribution from ETV expansion projects</li> <li>– Favorable price partially offset by lower volumes</li> </ul>

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

a) Amounts are adjusted for Certain Items.

b) Includes or represents DD&A, income tax expense, cash taxes and/or sustaining capital expenditures (as applicable for each item) from JVs.

c) Includes cash taxes from JVs of \$79 million and \$76 million in 2024 and 2023, respectively.

d) Includes sustaining capital expenditures from JVs of \$182 million and \$154 million in 2024 and 2023, respectively.

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

# 2024B Capital Expenditures

\$ in Millions

	2024 Budget	2023 Actual	Change
<b>Sustaining Capital</b>			
Natural Gas Pipelines	\$ 707	\$ 592	\$ 115
Products Pipelines	167	150	17
Terminals	229	224	5
CO <sub>2</sub> <sup>(a)</sup>	36	22	14
Corporate/Other	33	34	(1)
<b>Total sustaining capital expenditures for DCF<sup>(b)</sup></b>	<b>\$ 1,172</b>	<b>\$ 1,022</b>	<b>\$ 150</b>

	2024 Budget
<b>Discretionary Capital</b>	
Natural Gas Pipelines <sup>(c)(d)</sup>	\$ 1,749
Products Pipelines	75
Terminals	126
CO <sub>2</sub> - Source & Transport/Oil & Gas <sup>(e)</sup>	237
CO <sub>2</sub> - Energy Transition Ventures	88
Corporate/Other	1
<b>Total discretionary capital</b>	<b>2,276</b>
Sustaining capital expenditures for DCF <sup>(a,b)</sup>	1,172
JV Sustaining capital expenditures	(182)
Acquisitions <sup>(d)(e)</sup>	-
Contributions to unconsolidated JVs	(190)
Increase in capital accruals and other	-
<b>Capital expenditures (GAAP)</b>	<b>\$ 3,076</b>

- a) CO<sub>2</sub> sustaining capital includes \$15 million and \$9 million for ETV in 2024 and 2023, respectively.  
b) Includes sustaining capital expenditures from JVs of \$182 million and \$154 million in 2024 and 2023, respectively.  
c) Includes KM share of JV expansion spending of \$190 million and \$218 million in 2024 and 2023, respectively.  
d) 2023 includes \$1,817 million for STX Midstream acquisition.  
e) 2023 includes \$13 million for CO<sub>2</sub> acquisitions.

## Key Projects

### Sustaining Capital

- |             |   |
|-------------|---|
| Natural Gas | <ul style="list-style-type: none"> <li>– Class changes</li> <li>– Pipeline integrity / Mega Rule</li> <li>– Turbine exchanges</li> <li>– Air regulations</li> </ul> |
|-------------|---|

### Discretionary Capital

- |                 |  |
|-----------------|--|
| Natural Gas     | <ul style="list-style-type: none"> <li>– TGP Evangeline Pass project</li> <li>– Kimmeridge Eagle Ford project</li> <li>– Tejas South Texas to Houston project</li> <li>– Intrastate &amp; Midstream pipeline projects</li> </ul> |
| Products        | <ul style="list-style-type: none"> <li>– Hiland crude well connects</li> <li>– West Coast refined products projects</li> </ul>   |
| Terminals       | <ul style="list-style-type: none"> <li>– GRT Renewable Feedstock Hub</li> </ul>  |
| CO <sub>2</sub> | <ul style="list-style-type: none"> <li>– SACROC &amp; Diamond M development projects</li> <li>– RNG &amp; CCS projects</li> </ul>  |

# 2024B Cash Flow from Operations (CFFO) & Free Cash Flow (FCF)

\$ in Millions

	2024	2023	Change	
	Budget	Actual	\$	%
<b>Net income attributable to KMI</b>	<b>\$ 2,726</b>	<b>\$ 2,391</b>	<b>\$ 335</b>	<b>14%</b>
Net income attributable to noncontrolling interests	106	95	11	12%
DD&A and amortization of excess cost of equity investments	2,411	2,316	95	4%
Deferred income taxes	742	710	32	5%
Earnings from equity investments	(934)	(838)	(96)	(11%)
Distribution of equity investment earnings <sup>(a)</sup>	846	755	91	12%
Contract prepayment	-	835	(835)	(100%)
Working Capital and other items	(54)	227	(281)	NM
<b>CFFO (GAAP)</b>	<b>5,843</b>	<b>6,491</b>	<b>(648)</b>	<b>(10%)</b>
Capital expenditures (GAAP)	(3,076)	(2,317)	(759)	(33%)
<b>FCF</b>	<b>2,767</b>	<b>4,174</b>	<b>(1,407)</b>	<b>(34%)</b>
Dividends paid (GAAP)	(2,561)	(2,529)	(32)	(1%)
<b>FCF after dividends</b>	<b>\$ 206</b>	<b>\$ 1,645</b>	<b>\$ (1,439)</b>	<b>(87%)</b>

2023 CFFO includes a \$835mm contract prepayment benefit

Attractive investments and excess cash flow creating additional shareholder value

Note: See Non-GAAP Financial Measures and Reconciliations.

a) Excludes distributions from equity investment in excess of cumulative earnings, \$366 million and \$228 million in 2024 and 2023, respectively. These are included in Cash Flows Used In Investing Activities on our Consolidated Statements of Cash Flows.

# 2024B Sources & Uses<sup>(a)</sup>

\$ in Millions

	2024 Budget
<b>Sources</b>	
CCFO (GAAP)	\$ 5,843
Revolver Borrowing/Debt Issuances <sup>(b)</sup>	1,707
Distributions from equity investments in CFFI <sup>(c)</sup>	366
Cash balance as of 12/31/2023	83
<b>Total sources</b>	<b>\$ 7,999</b>

	2024 Budget
<b>Uses</b>	
Capital expenditures (GAAP)	\$ 3,076
Dividends paid (GAAP)	2,561
Debt maturities	1,919
Contributions to Equity Investments	190
Other Uses <sup>(d)</sup>	253
<b>Total uses</b>	<b>\$ 7,999</b>

SOURCES & USES \$ in billions



a) High level view of sources and uses and will vary depending on discretionary use of free cash flow.  
b) KMI had \$1,989 million of commercial paper borrowings at year-end 2023  
c) Reflects distributions from equity investments in excess of cumulative earnings.  
d) Includes NCI share of CCFO and deferral of 2023 cash payments.

# Leverage & Liquidity<sup>(a)</sup>

\$ in Millions

	2024 Budget
Net Debt (Year End)	\$ 31,830
Adjusted EBITDA	\$ 8,156
<b>Net Debt<sup>(b)</sup> to Adjusted EBITDA</b>	<b>3.9x<sup>(c)</sup></b>

KMI revolver capacity	12/31/2023
Committed revolving credit facility <sup>(d)</sup>	\$ 3,500
CP / Revolver borrowing <sup>(e)</sup>	(1,989)
Letters of credit	(81)
<b>Available capacity</b>	<b>\$ 1,430</b>

~12-year average maturity life &  
~5.3% weighted average interest rate

Decreased floating rate exposure  
by \$1.3bn to \$6.2bn in 2023

Note: See Non-GAAP Financial Measures and Reconciliations.

a) Debt of KMI and its consolidated subsidiaries excluding fair value adjustments.

b) Debt as defined in footnote (a), net of cash and foreign exchange impact on Euro denominated debt.

c) Long-term leverage target of around 4.5x.

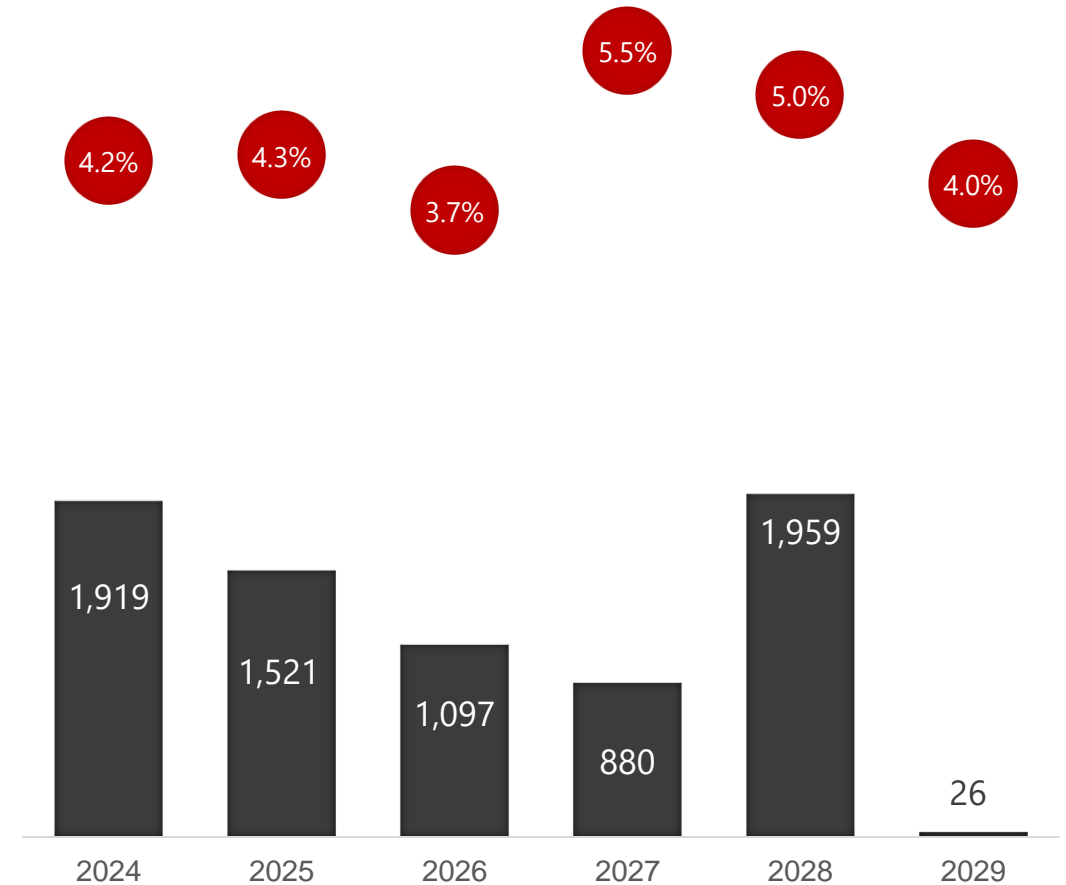
d) KMI corporate revolver facility of \$3.5 billion (August 2027 maturity).

e) Includes borrowings to fund the STX Midstream acquisition that closed on December 28, 2023.

f) Maturity schedule includes KMI's consolidated long-term debt, excluding fair value adjustments, \$220 million preferred securities, \$9 million non-cash foreign exchange impact on Euro denominated debt, and immaterial capital lease and other obligations.

## KMI LONG-TERM DEBT MATURITIES<sup>(f)</sup>

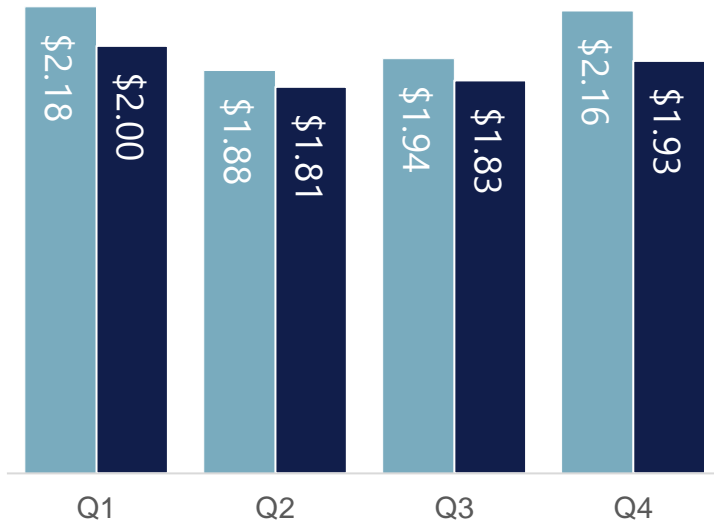
■ Debt maturities ● Weighted average interest rate



# 2024B Quarterly Profile

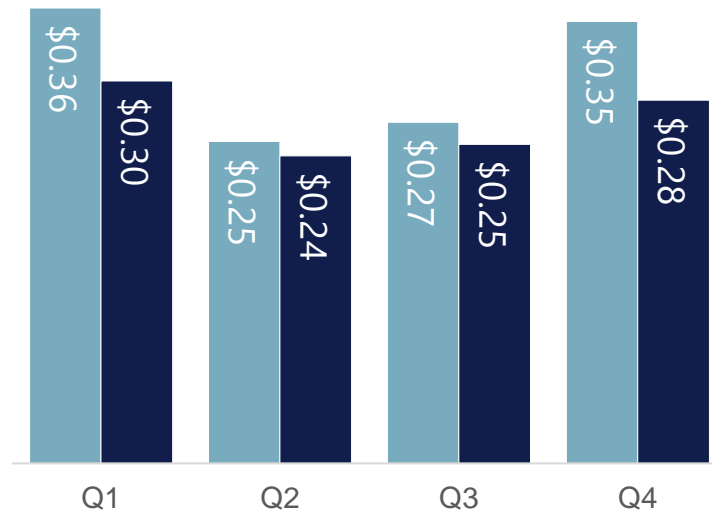
## ADJUSTED EBITDA in \$ billions

■ 2024 Budget ■ 2023 Actuals



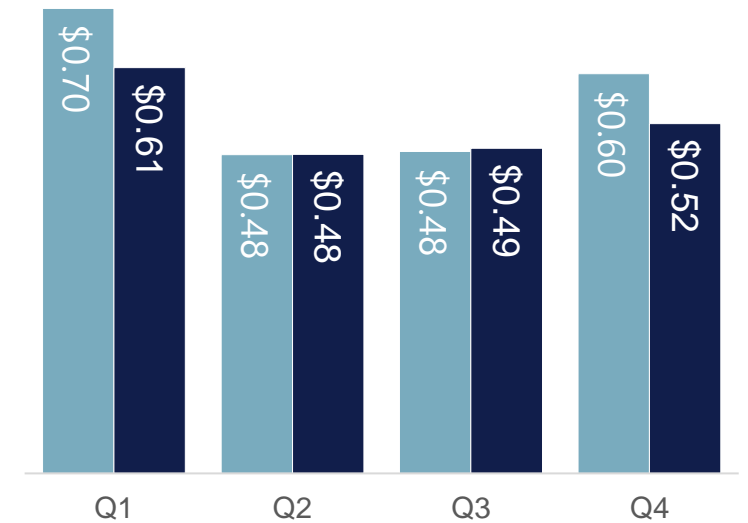
## ADJUSTED EPS

■ 2024 Budget ■ 2023 Actuals

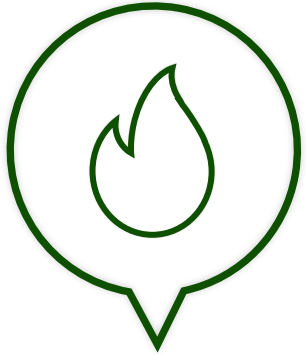


## DCF PER SHARE

■ 2024 Budget ■ 2023 Actuals



# How Kinder Morgan Drives Shareholder Value



Natural Gas Focus

Balance Sheet Strength

High-Returning Projects

Predictable & Growing Cash Flows

Substantial Shareholder Returns

# APPENDIX



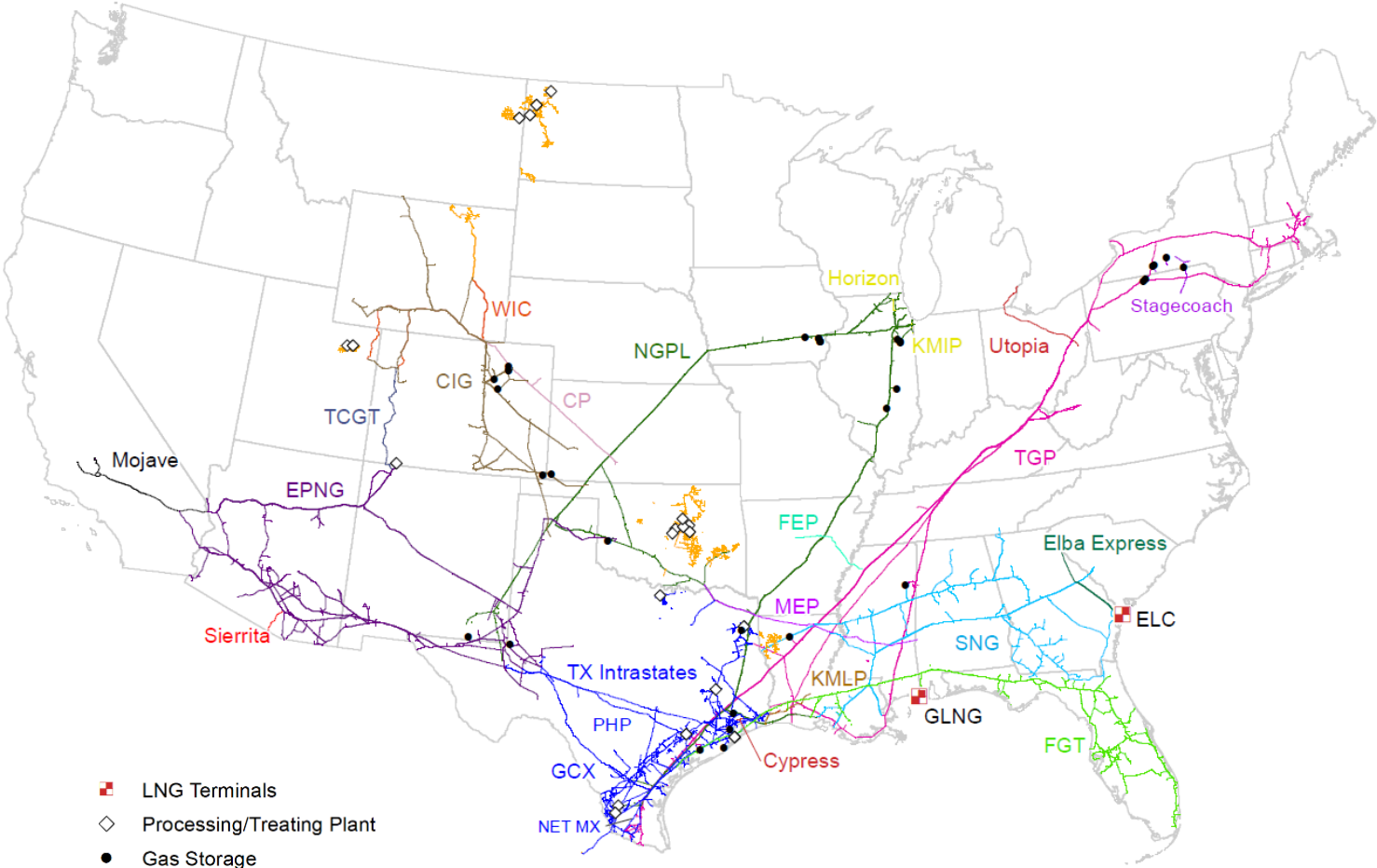
# Natural Gas

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Segment Presentation

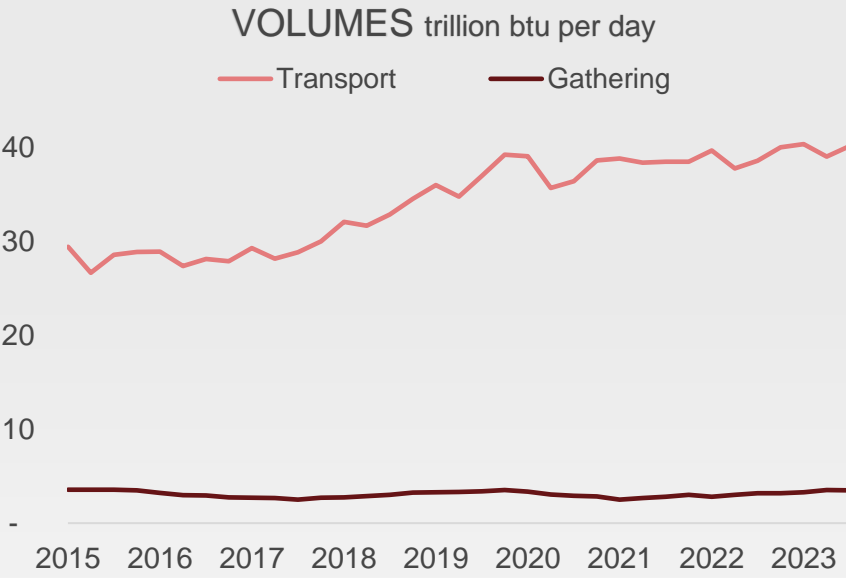
# Natural Gas Segment Overview

Connecting Key Natural Gas Resources with Major Demand Centers



## ASSET SUMMARY

Natural gas pipelines:	~70,000 miles
NGL pipelines:	~1,200 miles
Natural gas transported (U.S. consumption & exports)	~40%
Working gas storage capacity:	702 bcf

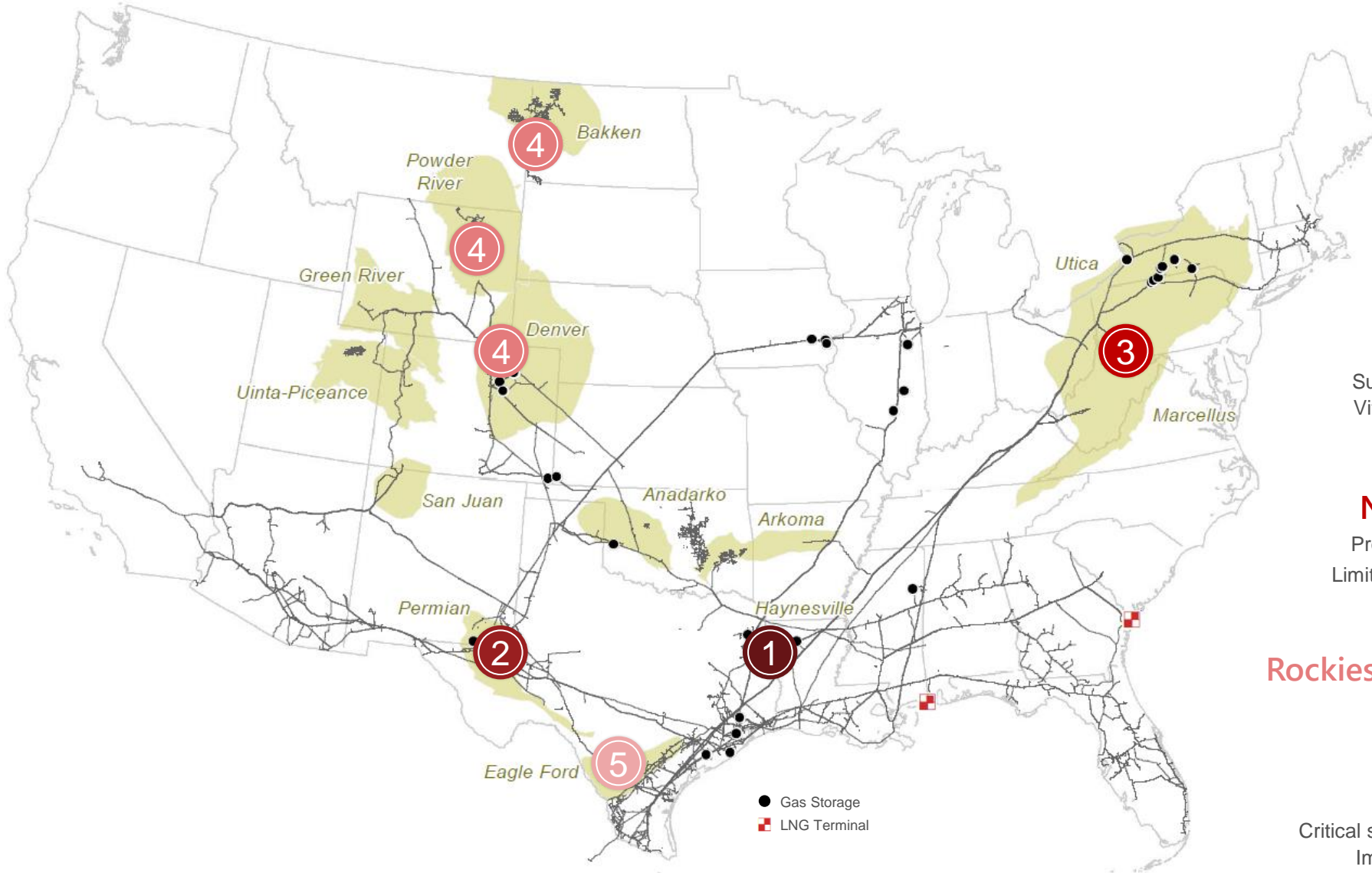


Largest natural gas transmission network in the U.S.

# Natural Gas Supply Overview: 2023 – 2030



2023 U.S. Production  
**104 bcf/d**  
 Increase in supply by 2030  
**+19 bcf/d**



**Haynesville** +9 bcf/d of growth **1**  
 Abundant, low-cost, low-nitrogen supply  
 Key to serving Gulf Coast demand markets

**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

**Northeast** +5 bcf/d from the Marcellus/Utica **3**  
 Production constrained despite ample, low-cost supply  
 Limited infrastructure opportunity despite strong demand

**Rockies** +0.7 bcf/d Powder River/DJ; +0.6 bcf/d Bakken **4**  
 Serves Rockies and West Coast demand

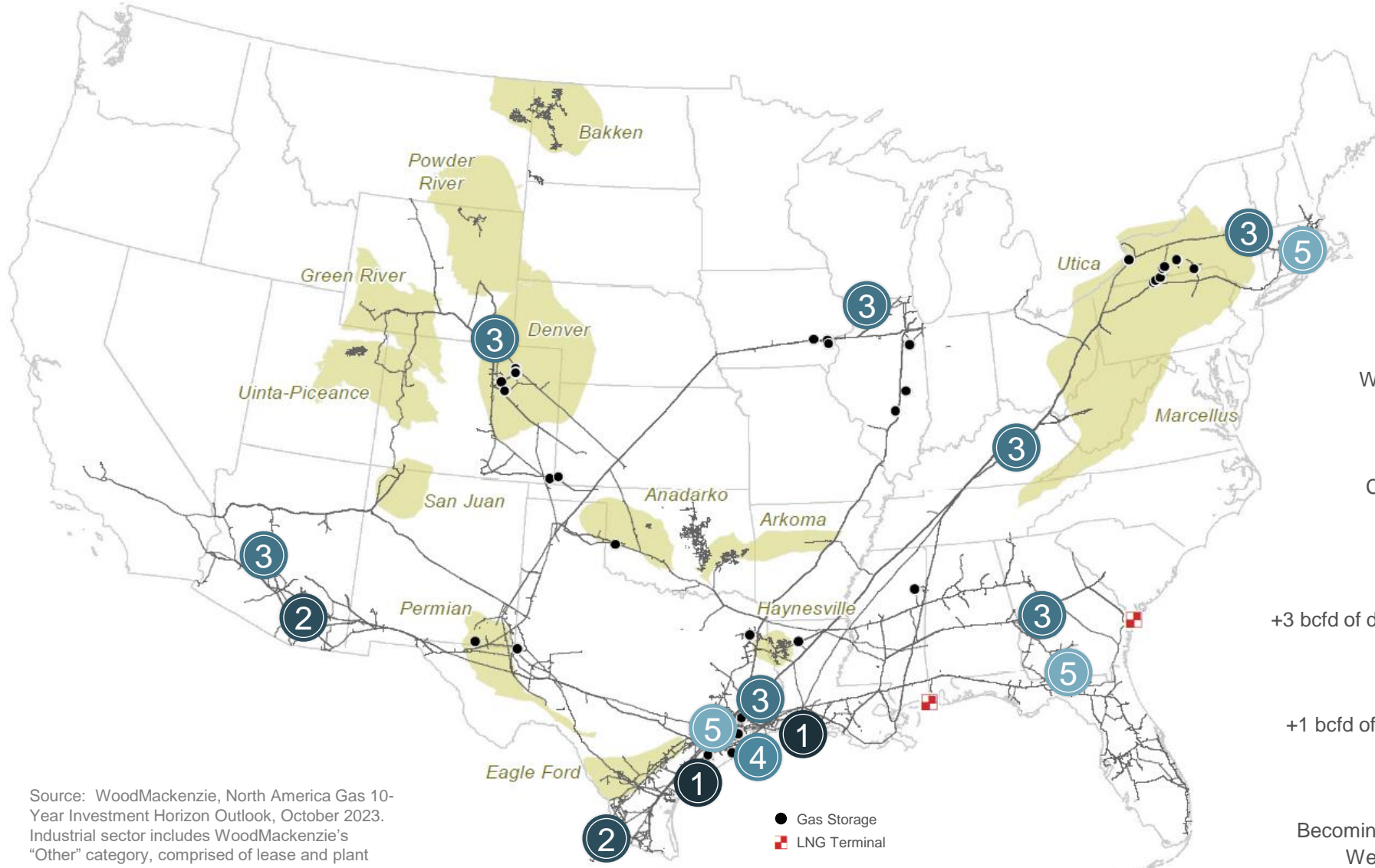
**Eagle Ford** +0.5 bcf/d of growth **5**  
 Critical supply link to Gulf Coast; potential upside to forecast  
 Important source of low-nitrogen gas for LNG facilities

Source: WoodMackenzie, North America Gas 10-Year Investment Horizon Outlook, October 2023.

# Natural Gas Demand Overview: 2023 – 2030



2023 U.S. Demand  
**108 bcf/d**  
 Increase in demand by 2030  
**+20 bcf/d**



## LNG Feedgas ①

+16 bcf/d of Gulf Coast demand growth  
 Well positioned to grow our deliveries over time

## Mexico Exports ②

+3 bcf/d of export demand growth  
 We can deliver into Mexico at multiple strategic points

## Power Demand ③

Capacity needed to backstop intermittent renewables  
 Coal retirements/coal-to-gas conversions

## Industrial Demand ④

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

## Residential & Commercial ⑤

+1 bcf/d of growth driven by the Southern U.S. & New England

## Storage

Becoming increasingly important to support variable demand  
 We have interest in 702 bcf of working storage capacity

Source: WoodMackenzie, North America Gas 10-Year Investment Horizon Outlook, October 2023. Industrial sector includes WoodMackenzie's "Other" category, comprised of lease and plant fuel. LNG feedgas equals exports plus an assumed 9% increase for plant fuel. This volume would otherwise be included in the Industrial category.

# Transporter of Choice for LNG Facilities

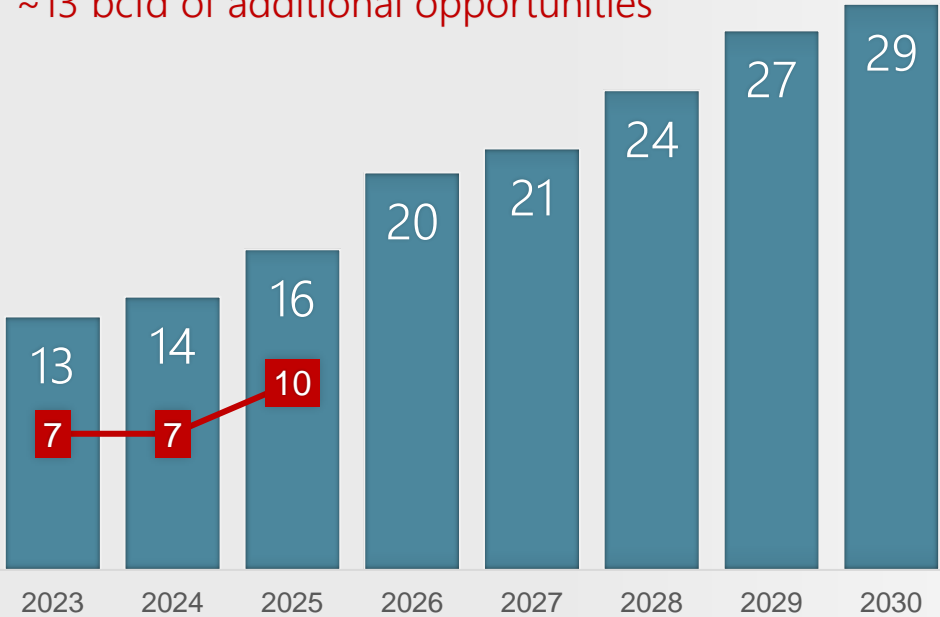
Advantaged Network Offers Supply Diversity, Connectivity, and Storage

U.S. LNG FEEDGAS & KM TRANSPORT bcf/d

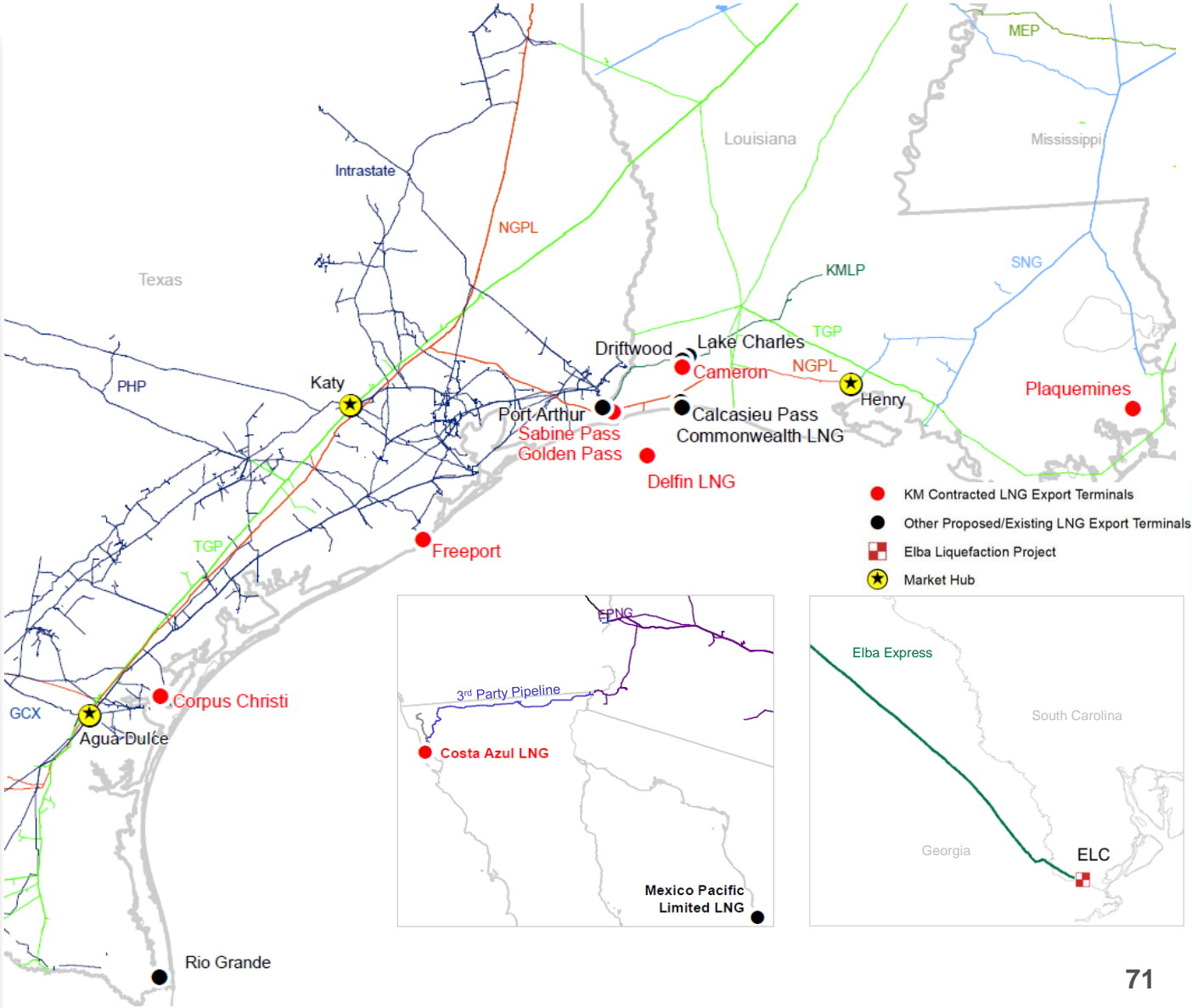
U.S. LNG Feedgas KM transport

long-term contracts to move ~7 bcf/d to facilities today & ~10 bcf/d by the end of 2025

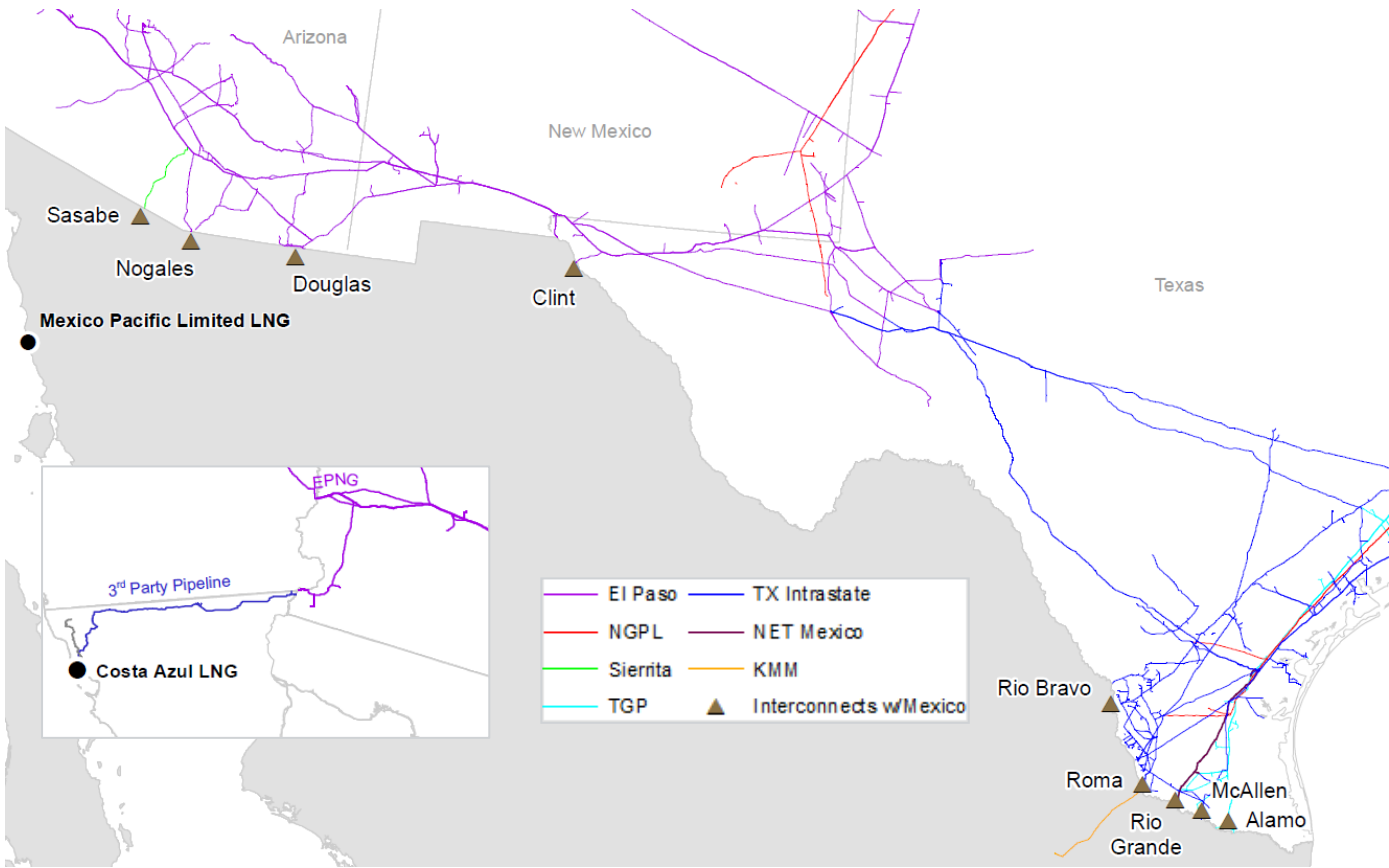
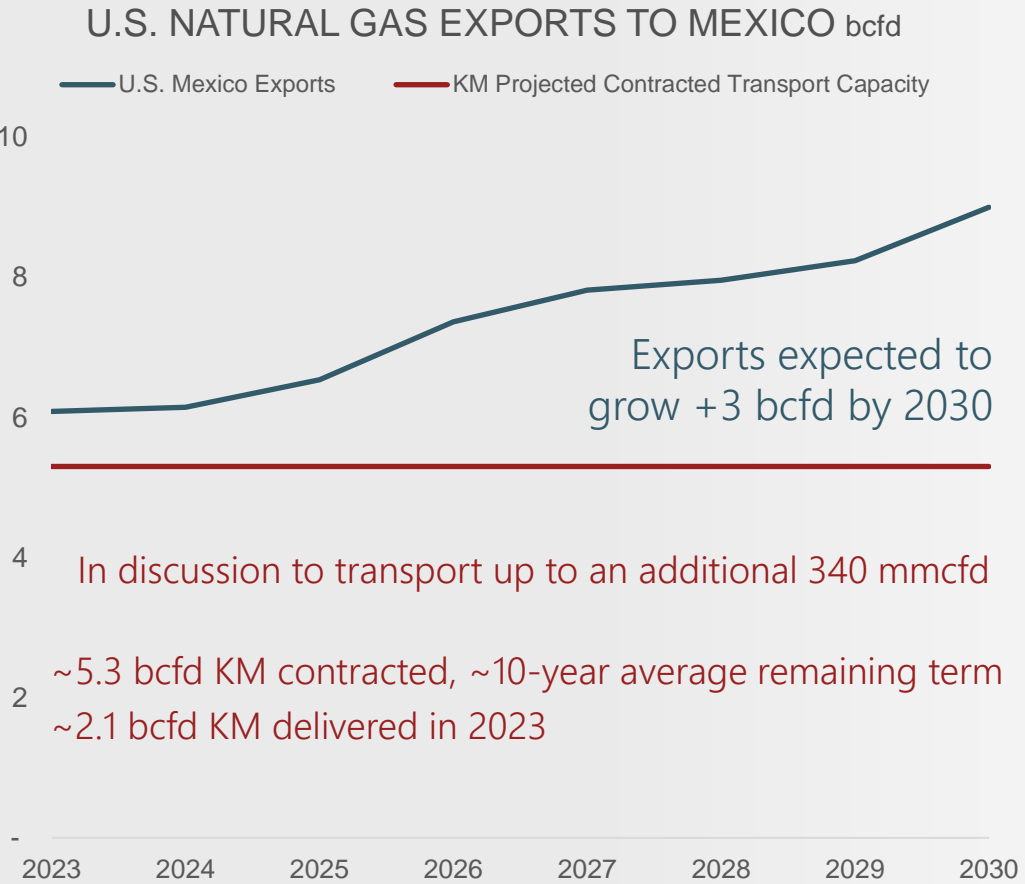
~13 bcf/d of additional opportunities



Source: WoodMackenzie, North America Gas 10-Year Investment Horizon Outlook, October 2023.  
 Note: WoodMackenzie exports are multiplied by 1.09 for an estimated feedgas figure.



# Key Market: Exports to Mexico



Evaluating additional opportunities to provide transportation, storage, and hub services

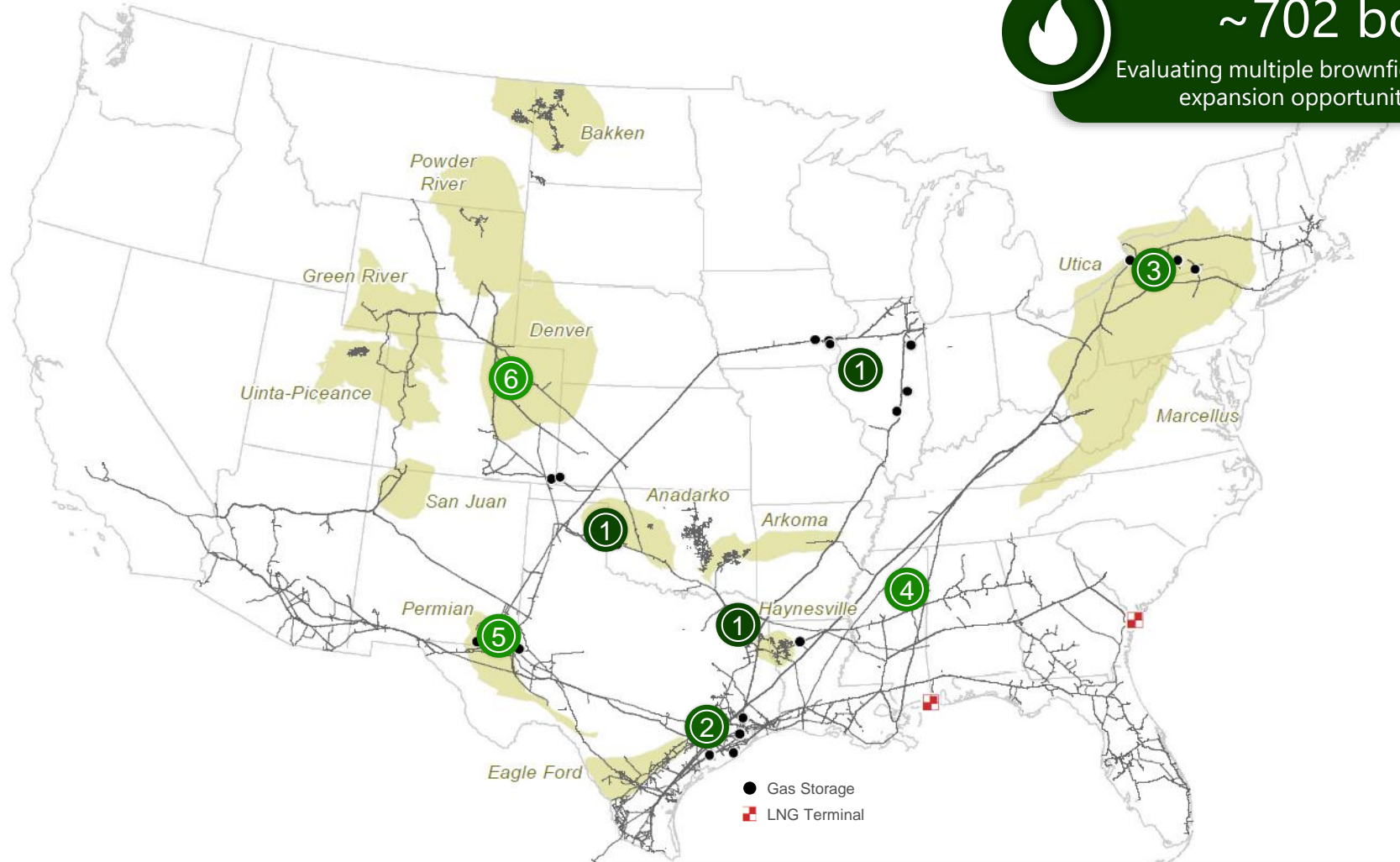
Provide supply diversity & serve multiple Mexico interconnections

Source: WoodMackenzie, North America Gas 10-Year Investment Horizon Outlook, October 2023.

# Extensive Natural Gas Storage Footprint Provides Valuable Supply for Variable Demand

KM working storage capacity  
**~702 bcf**  
 Evaluating multiple brownfield expansion opportunities

- ① NGPL**  
 Highly contracted storage key for seasonal & peak day power, LDC & industrial demand  
*288 bcf, cost-based rates*
- ② Texas Intrastates**  
 Highly responsive storage critical to serving LNG facilities & during extreme weather events  
*138 bcf, market-based rates*
- ③ TGP & Stagecoach**  
 Provide significant seasonal & peak day deliverability to Northeast markets  
*116 bcf; 41 bcf is market-based rates*
- ④ SNG**  
 Fully contracted with significant LDC & power demand  
*66 bcf, cost-based rates*
- ⑤ EPNG**  
 Highly utilized & fully contracted storage serves CA & AZ power demand  
*50 bcf, mostly cost-based rates*
- ⑥ CIG**  
 Fully contracted for LDC & power demand along the Colorado Front Range  
*44 bcf, cost-based rates*



Opportunity to capture greater storage values as demand grows, particularly in areas with market-based rates

# \$1.815bn Acquisition of NEP's South Texas Natural Gas Pipelines

462 Miles of Primarily Long-Haul Natural Gas Pipelines with 4.9 bcfd of Transport Capacity

## KMI acquired NEP's South Texas assets, STX Midstream

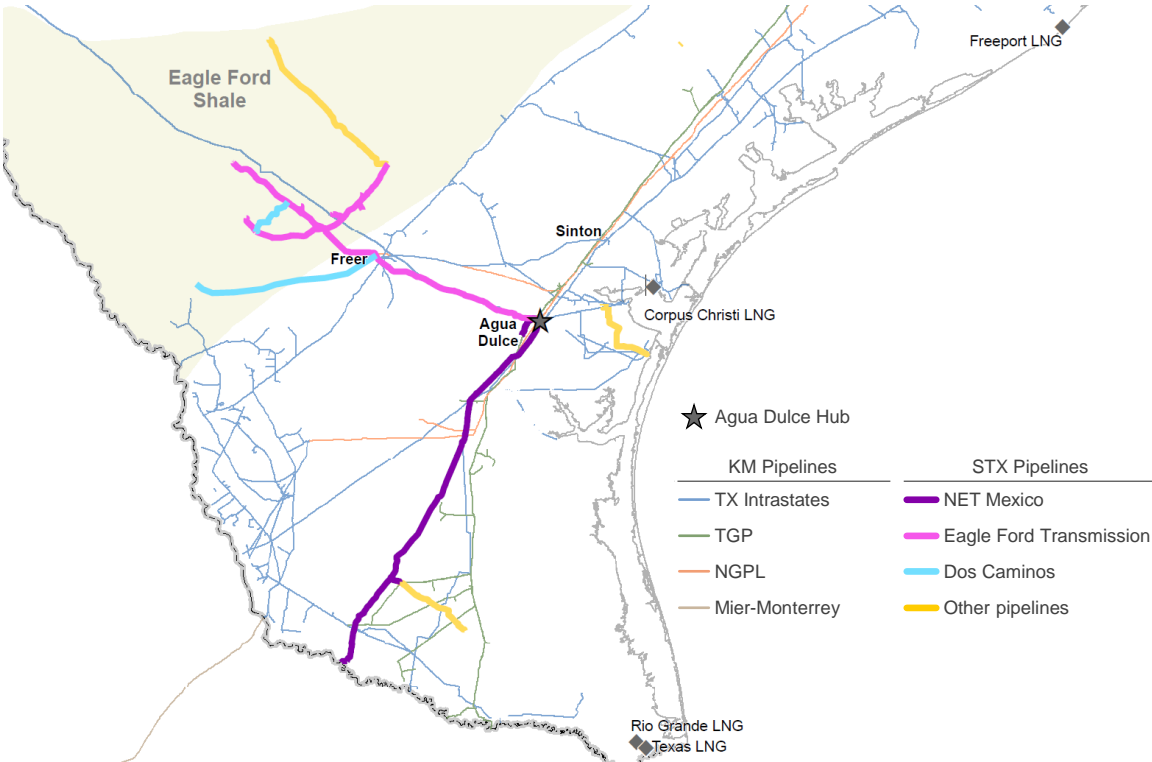
- ~8.6x 2024 EBITDA; 7.0-7.5x long-term including commercial synergies<sup>(a)</sup>
- Immediately accretive to DCF/sh and strongly free cash flow positive
- Increases Net Debt-to-EBITDA by ~0.1x<sup>(b)</sup>

## Intrastate assets complementary to KMI's existing South TX footprint

- Supports strategy to serve growing LNG, industrial, Mexican export, and power generation demand markets on the U.S. Gulf Coast
- Integrates with our existing intrastate/interstate footprint
  - Connections with multiple KMI assets including TX Intrastates, TGP and NGPL
  - Extends our direct connectivity in the lean area of the Eagle Ford basin
    - Opportunity to blend with supply from other KM assets to offer low-nitrogen natural gas desirable for LNG
  - Commercial synergies with existing and potential projects

## Stable fee-based infrastructure

- Fixed fee business; ~75% take-or-pay
- Average contract term >8 years; favorable renewal outlook
- Primarily supported by investment grade, direct end-use demand customers including Pemex, electric generation, and LDCs



## STX Midstream natural gas pipeline assets:

- **NET Mexico** (90% interest, operator); 120 miles, 2.2 bcfd capacity; connects Agua Dulce hub to U.S./MX border
- **Eagle Ford Transmission** (100% interest); 158 miles, 1.1 bcfd capacity; connects Eagle Ford to Agua Dulce hub
- **Dos Caminos** (50% interest); 75 miles, 1.2 bcfd capacity; delivers gas from Eagle Ford producers into EFM and TX Intrastates
- **5 other assets** (100% interest); 109 miles, 0.5 bcfd capacity; principally supplying demand-pull customers like power plants and LDCs

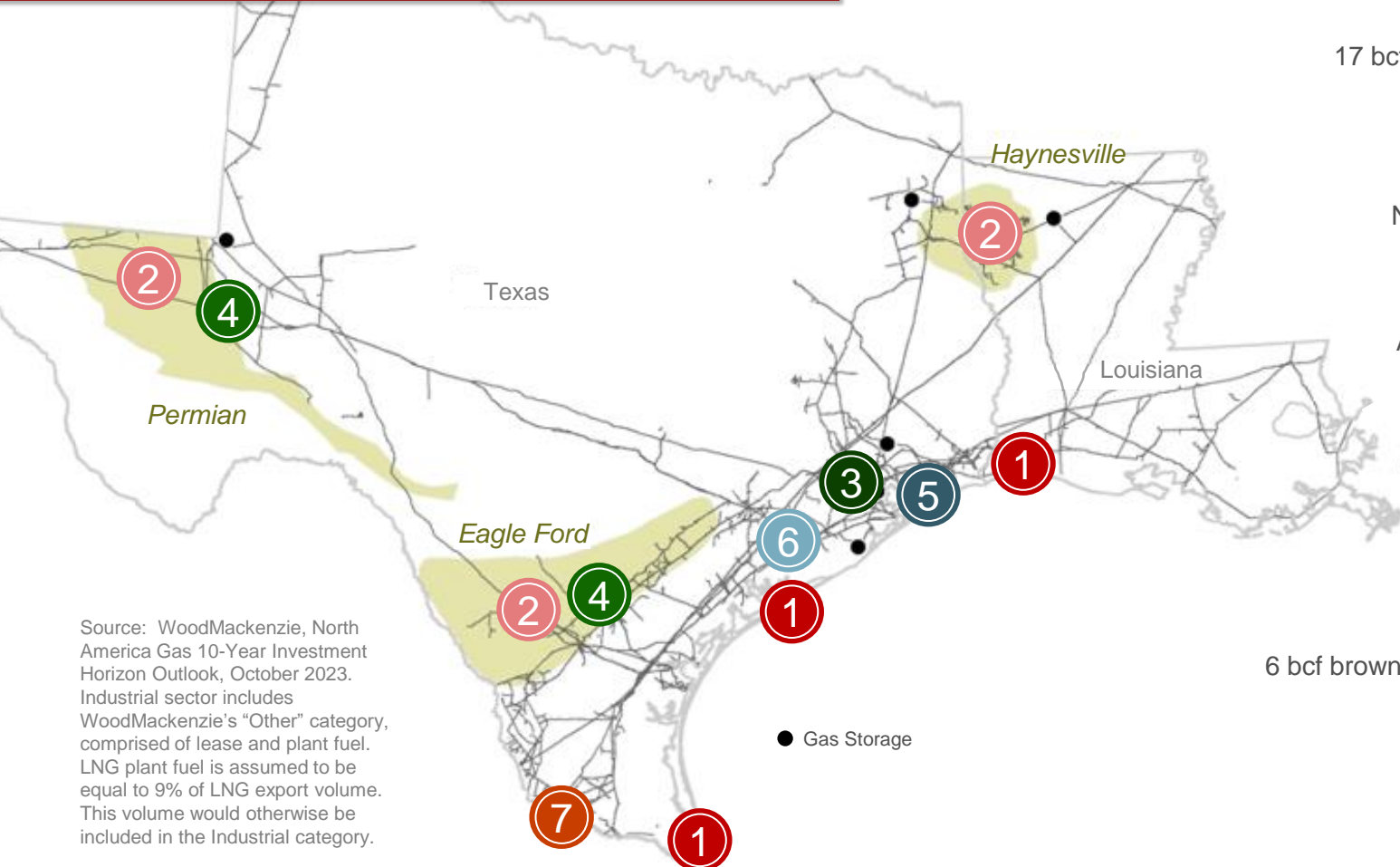
a) Based on KMI's financial projections.

b) With full-year EBITDA contribution from acquired assets. Based on longer-term funding plans, expect transaction to be neutral to KMI's balance sheet.

# Spotlight on Texas and Louisiana Natural Gas Market

>95% of Demand Growth is Expected to Occur in Texas & Louisiana, Driven by Exports & Industrial

~70% of our \$2.2bn Natural Gas backlog is located in Texas & Louisiana



Source: WoodMackenzie, North America Gas 10-Year Investment Horizon Outlook, October 2023. 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.

## LNG Exports ①

Gulf Coast feedgas demand set to grow 16 bcf by 2030  
Extensive network positioned to increase deliveries & offer supply diversification

## Supply Growth ②

17 bcf of growth out of the Permian, Haynesville, and Eagle Ford by 2030  
World-class basins, key to serving global natural gas demand

## Power Demand ③

Natural gas needed to backstop growing renewable power generation

## Pipeline Takeaway ④

Additional Permian & Eagle Ford egress needed as production grows

## Industrial Demand ⑤

+3 bcf of primarily Gulf Coast demand by 2030  
Network directly connects to industrial facilities along the Gulf Coast

## Storage Opportunities ⑥

Increased need for storage to serve growing intermittent demand  
6 bcf brownfield Markham storage expansion; evaluating additional opportunities

## Mexico Exports ⑦

Texas exports to Mexico forecasted to grow 2 bcf by 2030  
Expect our deliveries to Mexico to grow over time

# Natural Gas: Interstate Pipelines

## Key Statistics

		Ownership	Miles	Capacity (bcfd)	Storage (bcf)	Avg. Remaining Contract Term (yrs)	Effective Date of Next Rate Case	Rate Moratorium Through Date
<b>100% KMI-owned:</b>								
TGP	Tennessee Gas Pipeline	100%	11,755	12.4	76	6.1 / 3.7 <sup>(a)</sup>	NA	10/31/2022
SC	Stagecoach	100%	185	3.2	41	4.8 / 3.9 <sup>(a)</sup>	NA	12/31/2026
EPNG	El Paso Natural Gas + Mojave	100%	10,720	6.4	44	7.1	NA	9/30/2027
CIG	Colorado Interstate Gas	100%	4,300	6.0	38	5.5 / 4.8 <sup>(a)</sup>	4/1/2027	4/1/2026
WIC	Wyoming Interstate	100%	850	3.4	–	4.8	NA	4/1/2026
KMLP	Kinder Morgan Louisiana Pipeline	100%	140	3.9	–	16.7	NA	NA
CP	Cheyenne Plains	100%	415	1.2	–	2.0	NA	NA
TCGT	TransColorado	100%	310	0.8	–	0.6	NA	NA
EEC	Elba Express	100%	190	1.2	–	13.4	NA	NA
<b>Jointly-owned (asset stats shown at 100%):</b>								
NGPL	Natural Gas Pipeline Co. of America	37.5%	9,100	7.8	288	4.6 / 4.1 <sup>(a)</sup>	NA	NA
SNG	Southern Natural Gas	50%	6,925	4.4	66	3.5 / 1.6 <sup>(a)</sup>	9/1/2024	8/31/2021
FGT	Florida Gas Transmission	50%	5,380	4.4	–	9.3	9/1/2027	8/1/2024
FEP	Fayetteville Express	50%	185	2.0	–	0.9	NA	NA
MEP	Midcontinent Express	50%	515	1.8	–	1.8	NA	NA
	Sierrita	35%	60	0.5	–	15.8	NA	NA
<b>Storage &amp; LNG (asset stats shown at 100%):</b>								
	Keystone Gas Storage	100%	15	–	6	1.8	NA	NA
SLNG	Southern LNG Co. (Elba Island)	100%	–	1.8	12	8.8	NA	NA
GLNG	Gulf LNG	50%	5	1.5	7	7.8	NA	NA
ELC	Elba Liquefaction Company	25.5%	–	0.35	–	16.7	NA	NA
YGS	Young Gas Storage (CIG)	47.5%	15	–	6	5.0	4/1/2027	4/1/2026

a) Transport / Storage.

# Natural Gas: Intrastate, G&P and NGL Assets

## Key Statistics

	Ownership	Miles	Capacity (bcfd)	Storage (bcf)	Avg. Remaining Contract Term (yrs)	Treating (GPM)	Processing (bcfd)
<b>100% KMI-owned natural gas pipelines:</b>							
KMTP / Tejas	100%	5,870	9.1	138 <sup>(a)</sup>	6.3	1,680	0.5
North Texas Pipeline	100%	80	0.3	–	9.6	–	–
Mier-Monterrey	100%	90	0.6	–	7.1	–	–
South Texas system	100%	1,130	1.9	–	6.5	1,100	1.0
Camino Real Gathering – gas	100%	75	0.2	–	5.0	–	–
Hiland (Williston Basin) – gas	100%	2,200	0.6	–	10.8	–	0.3
KinderHawk	100%	570	2.4	–	life of lease	4,685	–
Altamont	100%	1,605	0.1	–	3.3	–	0.1
Oklahoma system	100%	3,175	0.7	–	2.1	80	0.1
Eagle Ford Transmission	100%	265	1.4	–	5.2	–	–
<b>Jointly-owned natural gas pipelines (asset stats shown at 100%):</b>							
Eagle Hawk Gathering – gas	25%	555	1.2	–	life of lease	–	–
Gulf Coast Express	34%	530	2.0	–	5.7	–	–
Webb/Duval Gas Gatherers	91%	140	0.2	–	3.0	–	–
Cedar Cove	70%	120	0.0	–	7.8	–	–
Bighorn Gas Gathering	51%	290	0.6	–	–	–	–
Fort Union Gas Gathering	50%	315	1.3	–	–	1,500	–
Permian Highway Pipeline	28%	435	2.7	–	7.6	–	–
Red Cedar Gathering	49%	860	0.3	–	2.7	4,600	–
Greenholly Gathering Pipeline	39%	40	1.2	–	9.6	–	–
NET Mexico	90%	120	2.2	–	11.0	–	–
Dos Caminos	50%	75	1.2	–	5.7	–	–
<b>Treating - Leased Units</b>	100%	Plants in service: 42 Amine / 31 Mechanical Refrigeration Units / 18 Dew Point					

	Ownership	Miles	Capacity (mbbl/d)	Storage (mbbl)	Avg. Remaining Contract Term (yrs)
<b>100% KMI-owned liquids pipelines:</b>					
South Texas NGL pipelines	100%	340	115	–	4.4
<b>Jointly-owned liquids pipelines (asset stats shown at 100%):</b>					
Liberty Pipeline	50%	85	140	–	4.4
Cypress (FERC Regulated)	50%	105	56	–	7.6
Utopia (FERC Regulated)	50%	265	50	–	15.0
Eagle Hawk Gathering- condensate	25%	410	220	60	life of lease

Note: KMTP/Tejas Includes term sale portfolio.

a) Includes 2 bcf of working gas storage capacity associated with the partial in-service of our Markham Storage expansion project. Expect the full 6 bcf online in 2Q 2024.

# Projects Placed Into Service During 2023

\$ Million

ASSET	PROJECT	IN-SERVICE DATE: 2023												CAPACITY (mDthd)	KM SHARE CAPITAL			
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec					
Texas Intrastates	Freer to Sinton																1,880	\$231
	PHP Compression Expansion																560	159
	Copano South DK Extension																310	57
TGP	East 300 Upgrade																115	267
	South Texas Expansion																122	26
	Coastal Bend Header																100	2
	Whistler Two Tap																29	1
FGT	Various Expansions															122	11	
CIG	South Pueblo 24B Blending															10	5	
NGPL	Red River West															200	4	
EPNG	Lusk Lateral															84	2	
<b>Subtotal Pipelines &amp; Storage, CCS</b>																	<b>\$766</b>	
<b>EBITDA build multiple</b>																	<b>5.1x</b>	
Gathering & Processing	KinderHawk Greenholly Pipeline and North Holly Expansion																521	125
	KinderHawk Redhawk System Expansion																270	77
	Hiland Williston Tier 1 Gas Expansion																various	56
	KinderHawk Plantation East Loop and BPX Incentive Wells																various	38
	EagleHawk Northeast CDP Phase II																190	17
	Altamont Bluebell Efficiency																4	16
	Copano EOG High West Project																130	14
<b>Subtotal Gathering &amp; Processing</b>																	<b>\$342</b>	
<b>Total Natural Gas Segment</b>																	<b>\$1,107</b>	

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

# Natural Gas Project Backlog

\$ Million

ASSET	PROJECT	KM SHARE CAPITAL	CAPACITY (mdTHD)	IN-SERVICE DATE	PROJECT STATUS
TGP	Evangeline Pass Projects	\$577	2,000	7/2024, 7/2025	Phase 1 under construction
	Port Sulphur Dispatch	70	235	11/2024	Under construction
	Cumberland Project	181	245	8/2025	Prior notice filed
	Sta. 40	78	200	11/2025	Under development
	Other TGP projects	26	89	various 2024	Under construction
Texas Intrastates	Markham C9 Conversion	46	6.1 Bcf	2Q24	Under construction
	Tejas South to North (Phase I)	97	350	3Q24	Under construction
	Central Texas Pipeline	115	225	4Q24	Under construction
SNG	Evangeline Pass Project	96	1,100	7/2025	Under development
	Other SNG projects	14	47	various 2024	Under development
NGPL	Permian North I	27	80	11/2024	Under development
	Texas-Louisiana	44	300	10/2026	FERC 7(c) Application Filed
FGT	South Louisiana	35	100	4/2025	Prior notice filed
	Other FGT projects	32	217	various 2024, 2025	various
EPNG	Maricopa Expansion	35	51	11/2025	Under development
	Other EPNG projects	27	293	various 2024, 2026	various
Red Cedar	CCS Project	38	25	4Q24	Under construction
WIC	Cheyenne to Questar Overthrust	26	180	5/2025	Prior notice filed
WYCO	Totem Storage Expansion	40	54	2/2026	Under development
Subtotal Pipelines & Storage, CCS EBITDA build multiple		<b>\$1,603</b> <b>5.0x</b>	Contracted, stable cash flows, minimal direct commodity exposure		
Gathering & Processing	Eagle Ford projects	180	400	various 2024	Under construction
	Altamont projects	113	32	various 2024, 2025	Under construction
	Bakken projects	81	48	various 2024, 2025	Under construction
	Haynesville projects	69	361	various 2024	Under construction
	Well connects / other	106	various	various 2024	Under construction
Subtotal Gathering & Processing		<b>\$549</b>	Primarily fixed-fee, volume-based cash flows		
<b>Total Natural Gas segment</b>		<b>\$2,152</b>			

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

# Products

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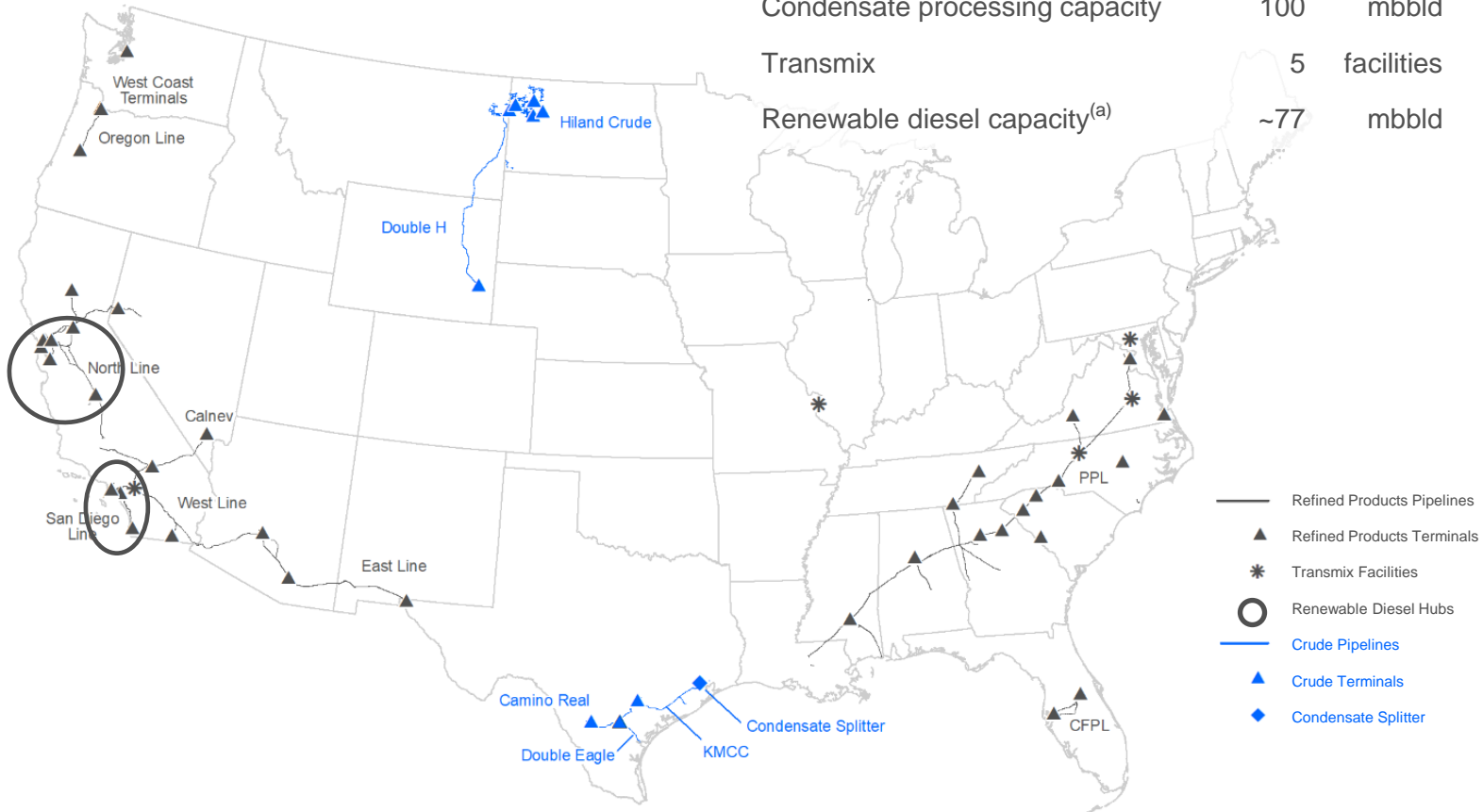
Segment Presentation

# Products Segment Overview

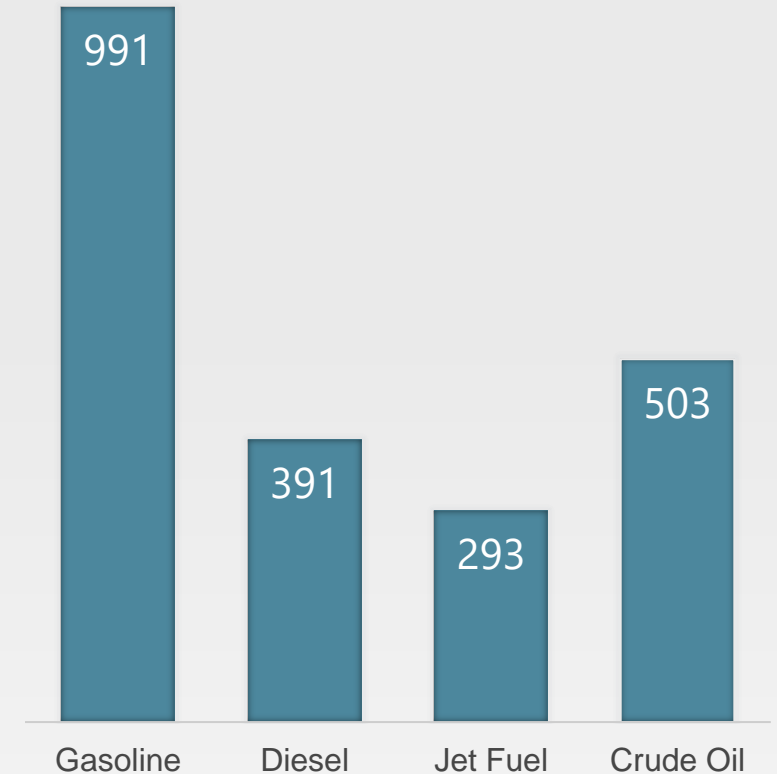
Strategic Footprint Supplying a Diverse Mix of Feedstock & Finished Products  
Critical to Refining & Transportation Sectors

## ASSET SUMMARY

Pipelines:	~9,500	miles	Terminals:	65	terminals
2024 budgeted throughput <sup>(a)</sup>	~2.2	mmbld	Tank capacity	~56	mmbls
			Condensate processing capacity	100	mmbld
			Transmix	5	facilities
			Renewable diesel capacity <sup>(a)</sup>	~77	mmbld



2024B DELIVERY VOLUMES<sup>(b)</sup> mbbld



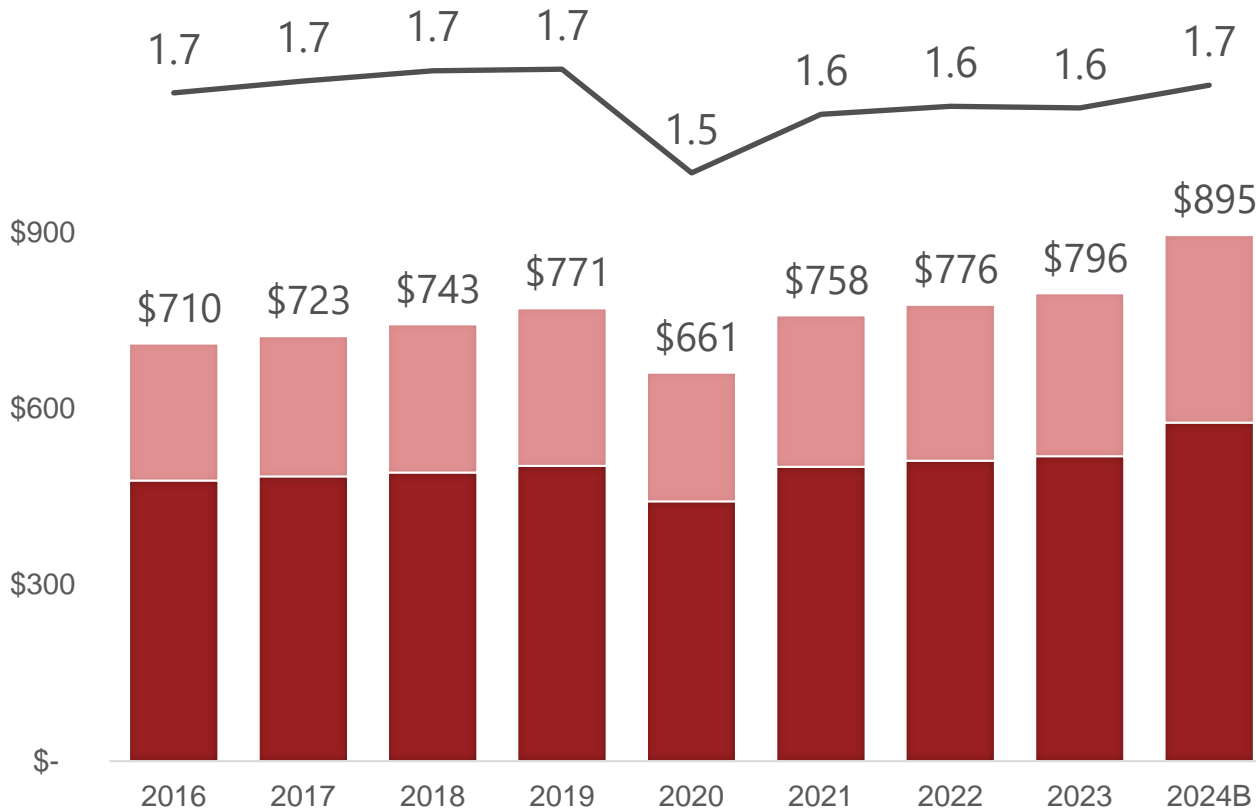
a) Includes RD hub capacity in Northern and Southern California, and Carson truck rack capacity.  
b) Kinder Morgan volumes include SFPP, CALNEV, Central Florida, PPL (KM share), KMCC, Camino Real, Double Eagle (KM share), Double H & Hiland Crude Gathering; Gasoline volumes include ethanol.

# Refined Products Pipes a Steady Contributor

Fee-Based With Stable Volumes and Cash Flow Over the Long-Term

REFINED PRODUCTS ADJUSTED SEGMENT EBDA BY REGION<sup>(a)</sup> AND TOTAL VOLUME<sup>(b)</sup>

West Coast (\$mm) Southeast (\$mm) Volume (mmbbl/d)



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

a) Contributions to Products Pipelines Adjusted Segment EBDA are from SFPP, CALNEV, West Coast Terminals, Central Florida, Transmix, PPL (KM share) & Southeast Terminals.

b) Kinder Morgan volumes include SFPP, CALNEV, Central Florida & PPL (KM share).

## Advantaged Network

- Offers unmatched connectivity between major refining centers & key demand markets
- Renewable diesel projects help maintain West Coast diesel market share on pipelines and enable expanded rack blending opportunities at the terminals
- Attractive, capital efficient blending opportunities
- FERC rate escalator on refined products pipes helps protect earnings against potential volume declines and/or cost inflation

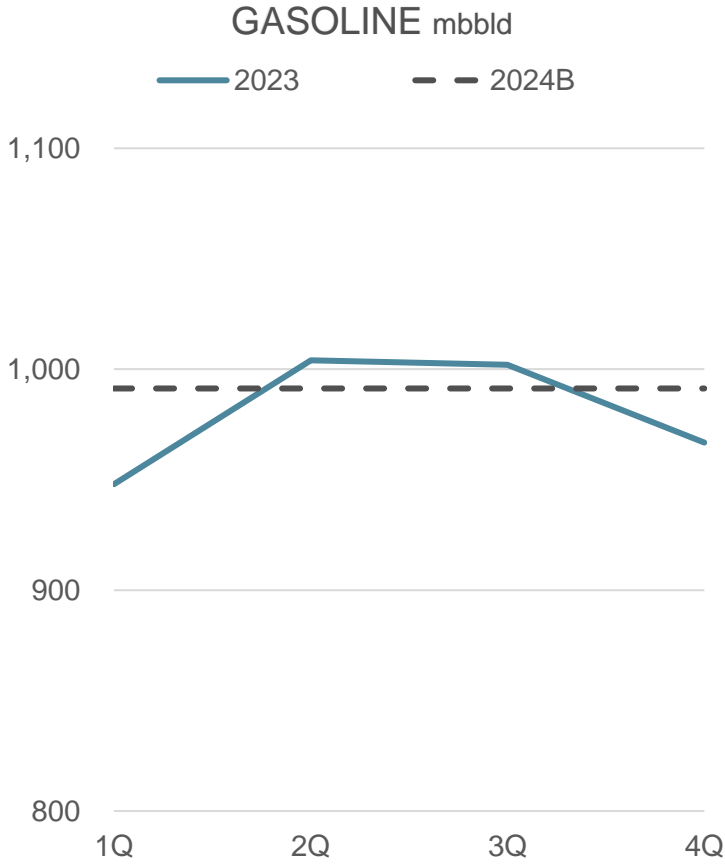
ADJ. SEGMENT EBDA CAGR

2.9%

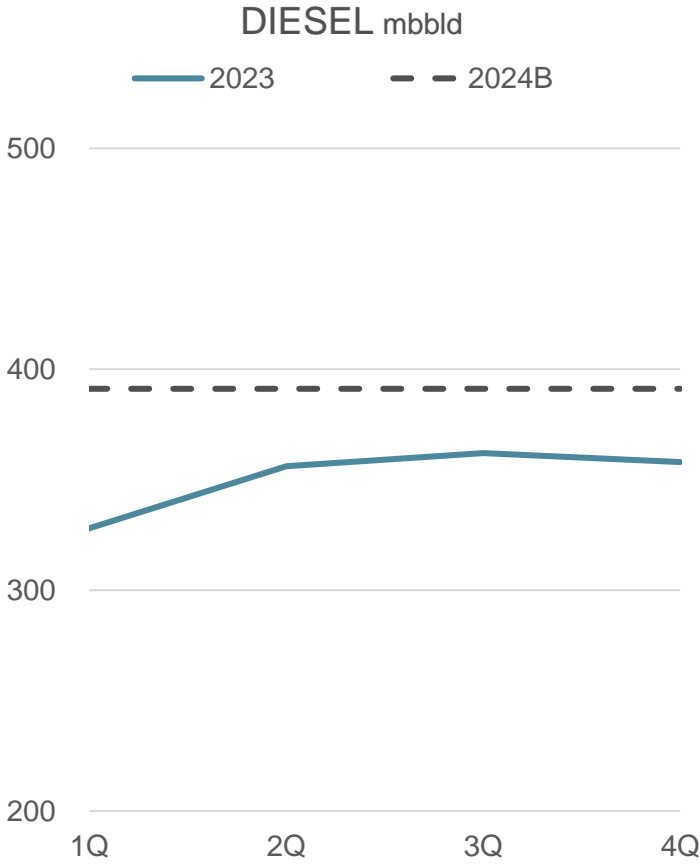
VOLUME CAGR

> 0.1%

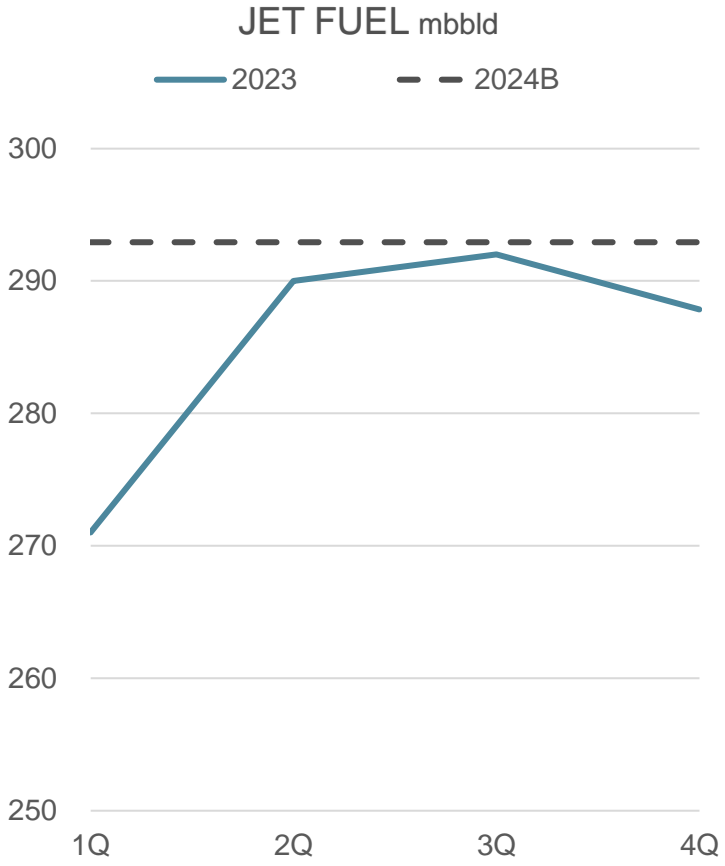
# Growing Refined Products Volumes



2024B: 991 mbbld  
 2023: 980 mbbld  
 Gasoline roughly flat



391 mbbld  
 351 mbbld  
 Diesel up 11%, recapturing RD bbls



293 mbbld  
 285 mbbld  
 3% jet growth

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

# Pivoting Product Segment's West Coast Assets to Handle Additional Renewable Diesel Volumes

CURRENT ASSETS & FUTURE OPPORTUNITIES	
<p><b>Southern California Hub</b> (RD by pipeline)</p>	<ul style="list-style-type: none"> <li>- Providing ~18 mbbl/d RD capacity at truck rack between Colton &amp; Mission Valley</li> <li>- Increasing biodiesel blend capabilities to 20% at Colton</li> </ul>
<p><b>Carson</b> (Port of LA)</p>	<ul style="list-style-type: none"> <li>- Providing ~20 mbbl/d RD capacity at truck rack</li> <li>- Converting ~750 mbbl storage capacity to RD</li> </ul>
<p><b>Northern California Hub</b> (RD by pipeline)</p>	<ul style="list-style-type: none"> <li>- Providing ~39 mbbl/d RD capacity at truck rack between Fresno, San Jose, and Bradshaw</li> </ul>
<p><b>Richmond</b> (Bay Area)</p>	<ul style="list-style-type: none"> <li>- Converting ~50 mbbl storage capacity to RD with access to the rack</li> </ul>
<p><b>Washington &amp; Oregon</b></p>	<ul style="list-style-type: none"> <li>- Evaluating potential conversion opportunities to handle RD</li> </ul>

ability to move  
**~57 mbbl/d**  
of RD via pipeline  
at our hubs

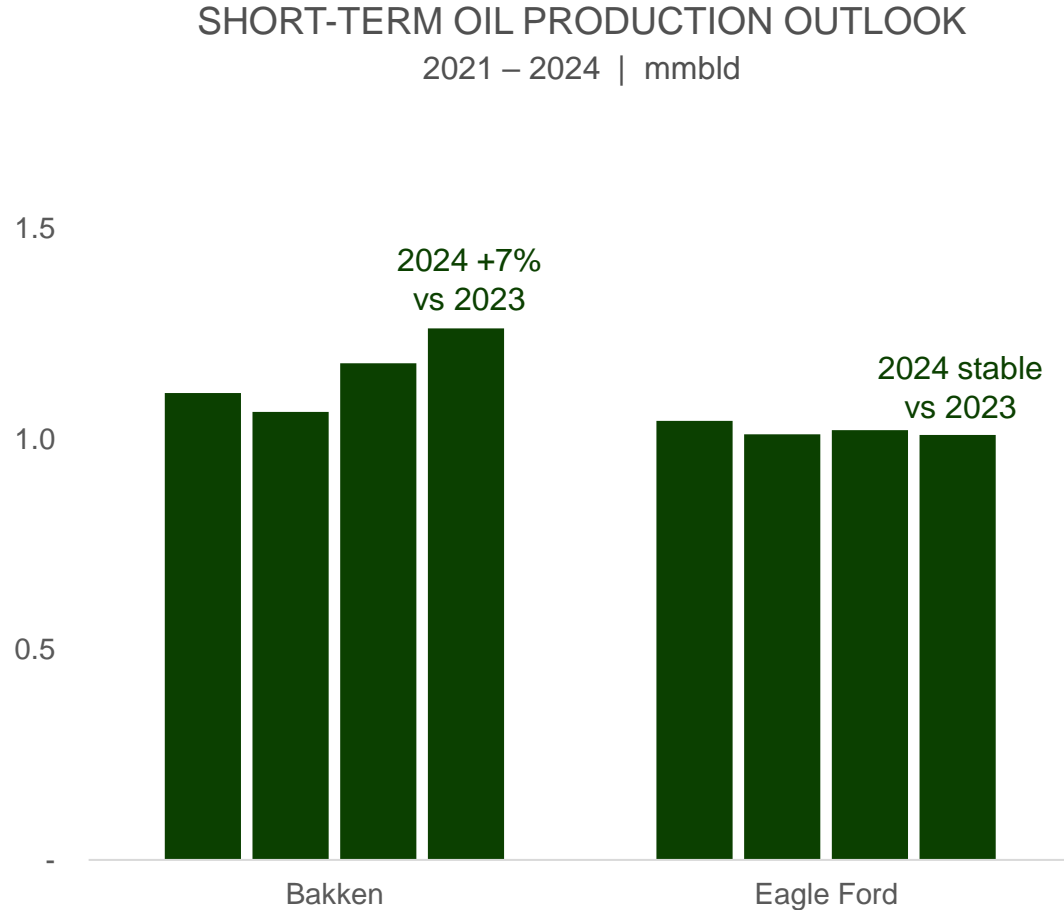
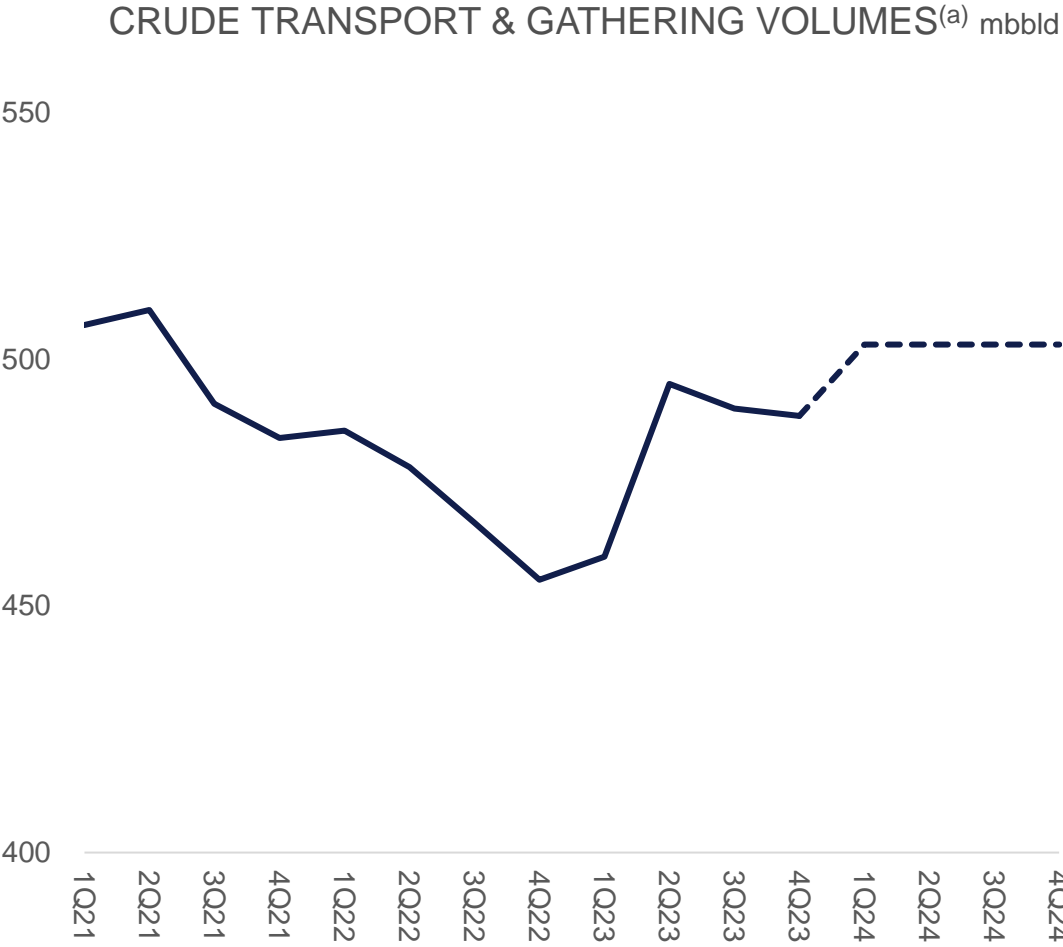


First company to transport RD via pipeline to market in the U.S.

Potential for additional expansion opportunities, including RD feedstock logistics

# Products Segment Crude Volume Update

Business as % of 2024B KMI Adjusted Segment EBDA: 2% Crude G&P; 2% Crude Transport

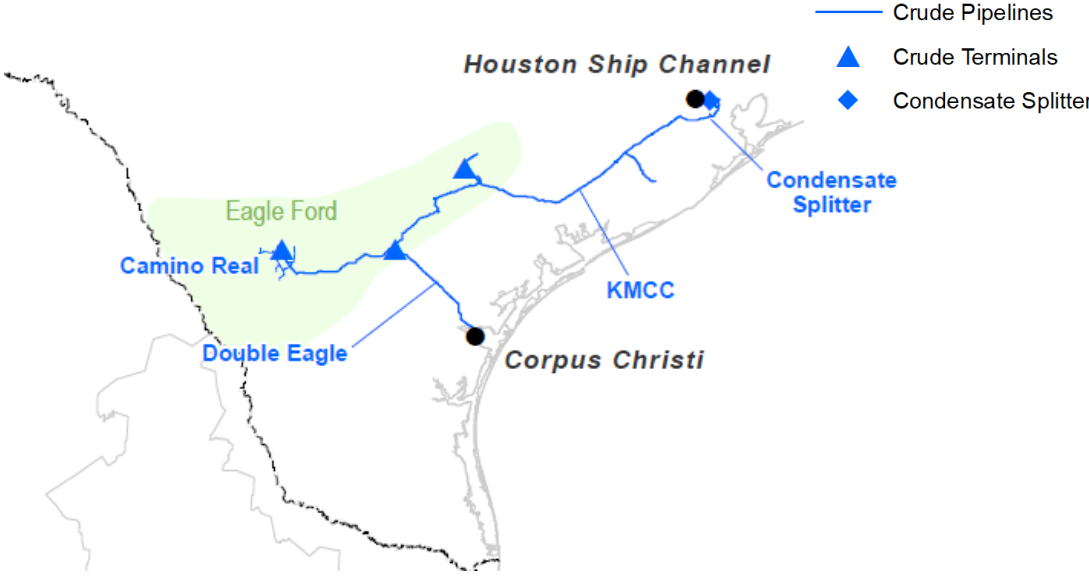


**Crude: 483 mmbld in 2023 | 503 mmbld 2024B**

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.

# Texas & Bakken Crude Oil Assets

Strategically Positioned in Eagle Ford & Bakken

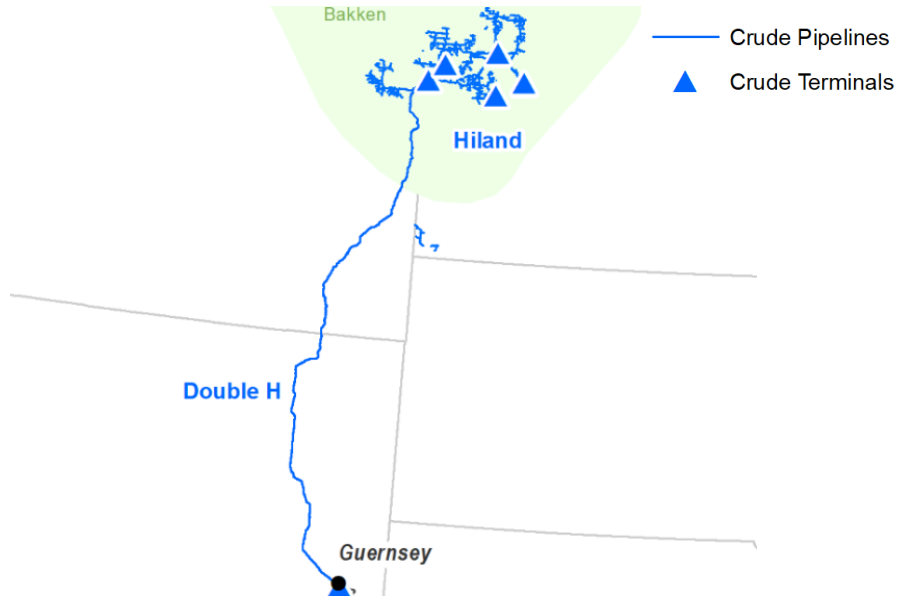


Texas crude assets offer connectivity to the Corpus Christi & Houston Ship Channel markets

- Flexibility to reach domestic refining capacity & export facilities

KMCC delivering Permian Basin volumes into Houston market via connection with Gray Oak pipeline

Condensate splitter located in the Houston Ship Channel with two processing units totaling 100 mbbld of capacity



Hiland is one of the Bakken's premier gathering systems

- Backed by dedications from key producers in the basin
- Strategically positioned in core Bakken acreage

Double H aggregates Hiland volumes for delivery into Cushing & other U.S. markets

- Joint tariff with Pony Express provides access to Cushing

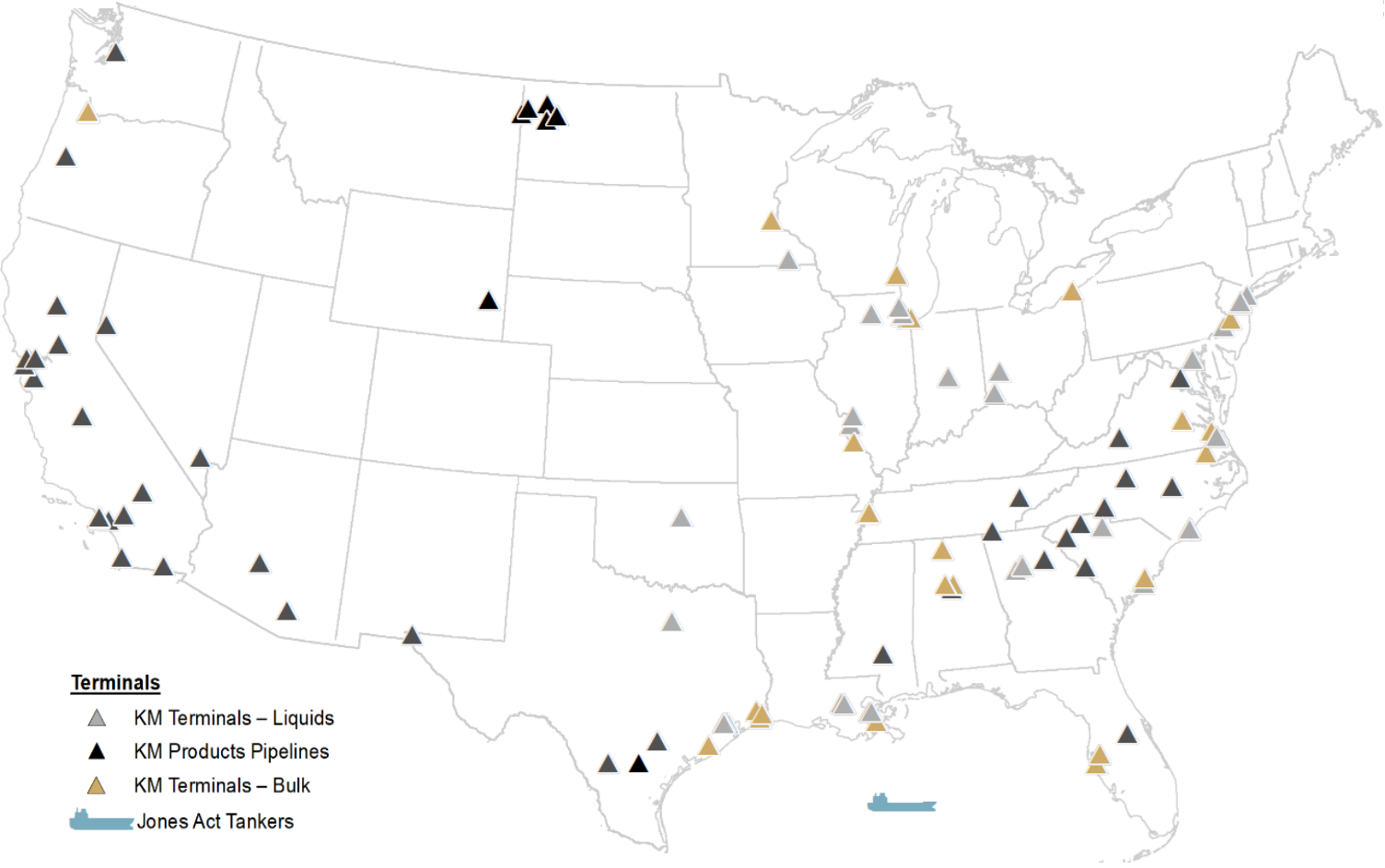
# Terminals

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Segment Presentation

# 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	27	
Terminals segment – Liquids	47	79
Products segment	65	56
<b>Total Terminals</b>	<b>139</b>	<b>135</b>
<b>Jones Act:</b>	<b>16 tankers</b>	

Nationwide footprint focused on refined products, renewables & chemicals

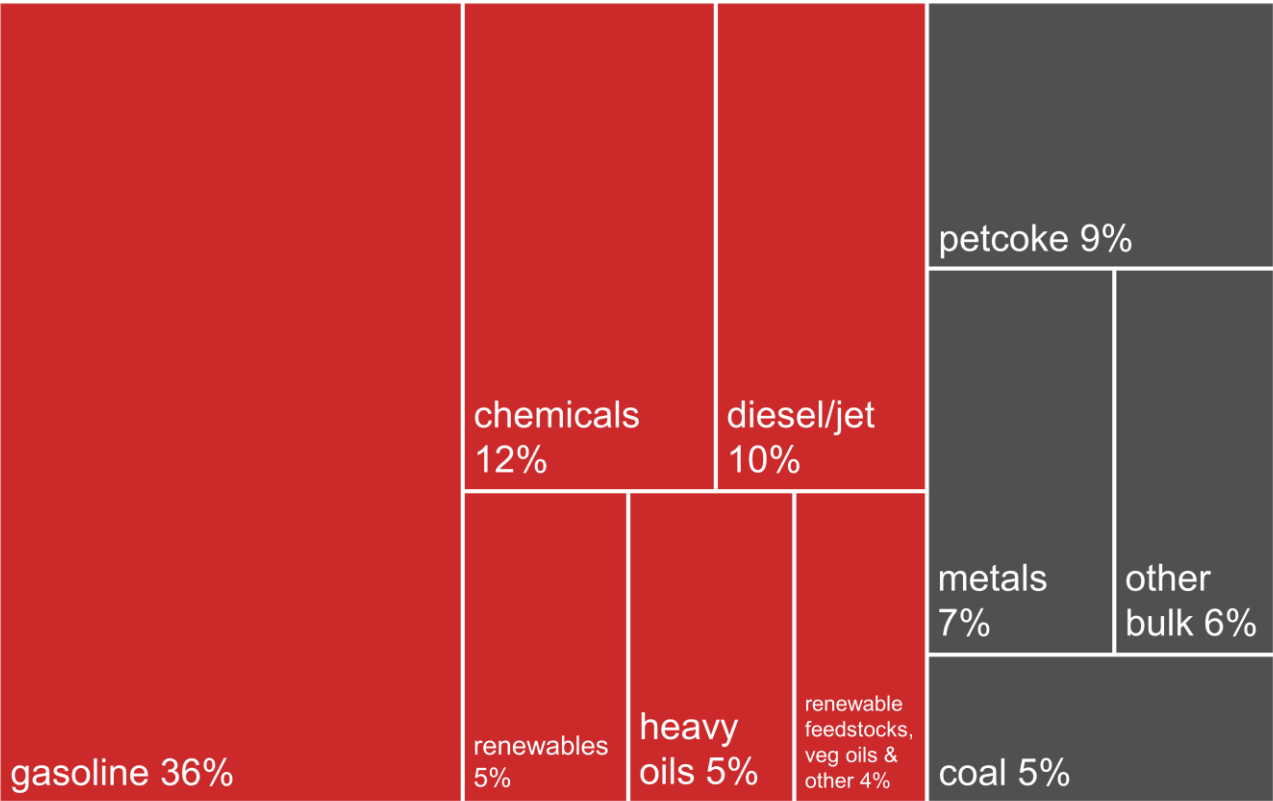
Earnings driven by long-term contractual use of our assets

Infrastructure critical to our customers & their business

# Terminals Segment Revenue by Product

Liquids-Focused Terminals with a Diverse Product Mix

2024B REVENUE: \$1.9 BILLION<sup>(a)</sup>



## 72% LIQUIDS

- Market-making industry hubs in key refining centers critical to our customers
- Complementary & synergistic with renewables & chemicals
- Jones Act tankers to meet domestic maritime demand
- Unmatched service offerings & flexibility to efficiently supply domestic & international markets

## 28% BULK

- Complementary petroleum coke logistics & export terminals serving the refinery industry
- Services to domestic steel manufacturing

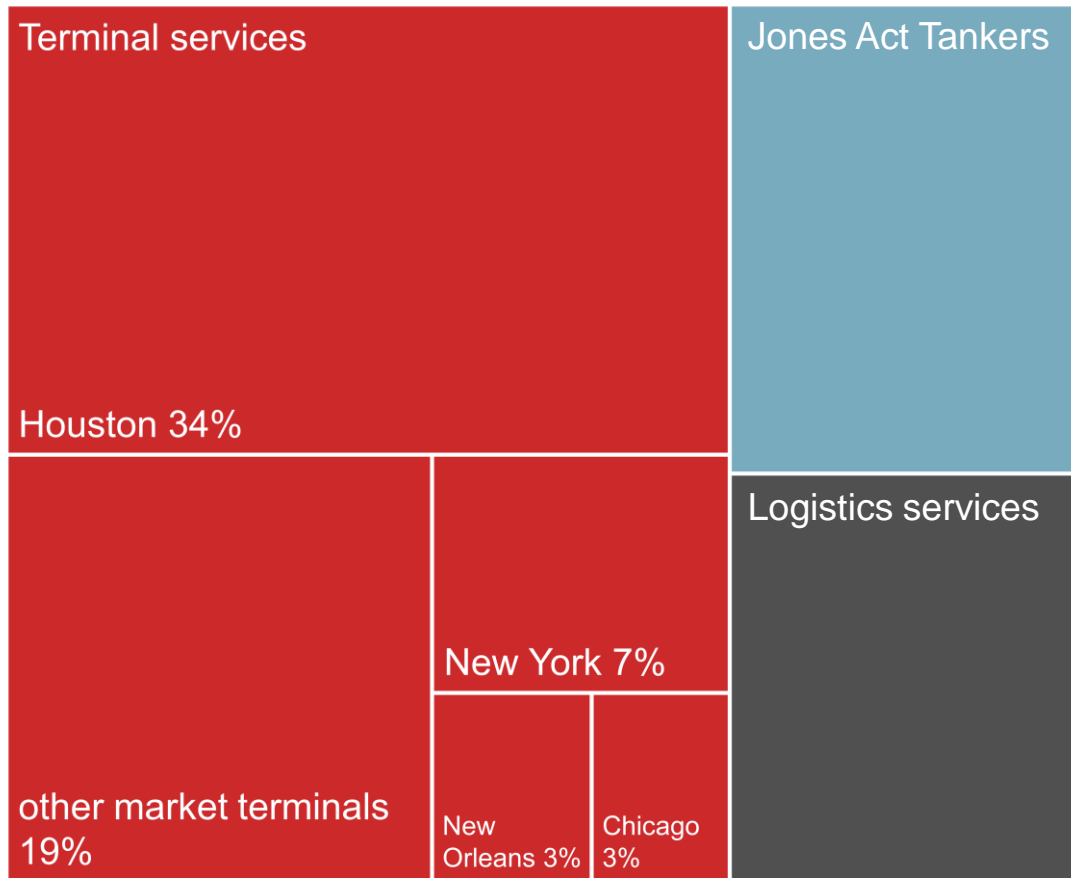
Partner to domestic refiners with the most competitive world-wide supply  
 Complementary renewables & chemicals services offering future growth

Note: Individual components may not sum to total due to rounding.  
 a) 2024 budgeted Terminals Segment revenues.

# Terminals Segment Services

Offering Unmatched Market Access with Modal Optionality Alongside Value-Added Terminaling Services

2024B ADJUSTED SEGMENT EBDA: \$1.1 BILLION



**Terminal services**  
67%

- Concentrated in key industry supply & demand market hubs
- Houston Ship Channel assets serving the world’s most competitive refining & petrochemical industry
- Complementary regional distribution terminals
- ***Allows indispensable connectivity to markets***

**Jones Act tankers**  
18%

- Most modern & efficient Jones Act tanker fleet
- Handle refined products, crude, and renewables with chemicals capabilities
- ***Meets domestic maritime demand***

**Logistics services**  
15%

- In-plant handling of steel, scrap & ores serving steel production
- Petroleum-coke handling supporting refineries
- In-plant logistics services supporting petrochemicals
- ***Serves world-class production facilities***

## Service offering of full supply chain logistics solutions

Note: Adjusted Segment EBDA is a non-GAAP measure. See Non-GAAP Financial Measures & Reconciliations. Individual components may not sum to total due to rounding.

# Liquid Hubs: Strategically Located to Serve Key Markets

**Houston Ship Channel** 9 terminals providing ~43 million barrels of capacity<sup>(a)</sup>

- Serves the world’s most competitive supply of refined products & petrochemicals

**New York Harbor** 5 terminals providing ~14 million barrels of capacity

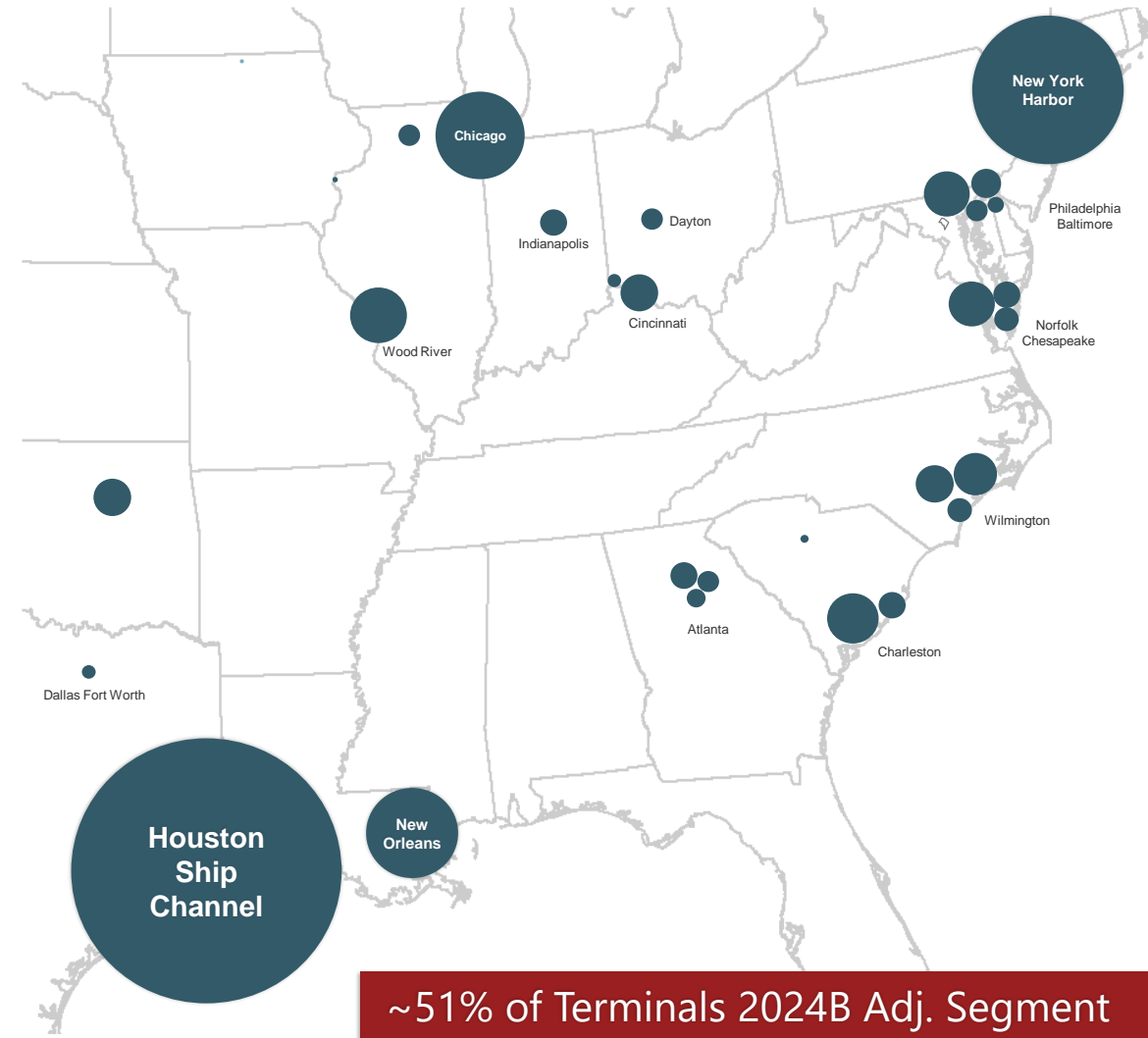
- Serves as the world’s largest & most liquid refined product clearinghouse

**New Orleans** 6 terminals providing ~5 million barrels of capacity

- Serves growing renewable & chemical markets along the Mississippi River

**Chicago** 4 terminals providing ~5 million barrels of capacity

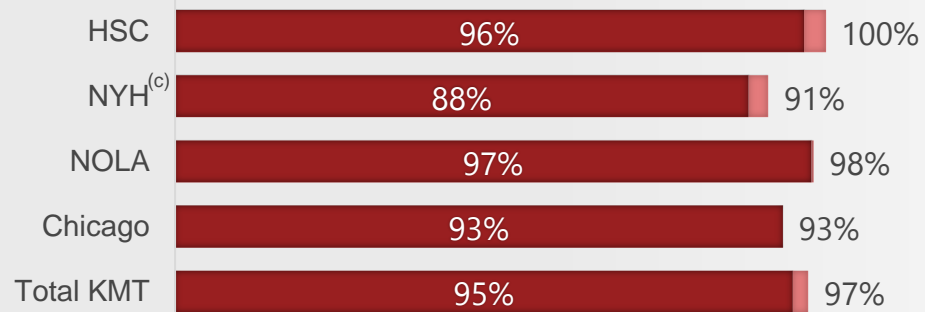
- Serves as the nation’s ethanol clearinghouse, pricing & trading hub



**~51% of Terminals 2024B Adj. Segment EBDA generated from Liquid hubs**

2024B LIQUIDS UTILIZATION<sup>(b)</sup>

■ Leased ■ API



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

a) Houston Ship Channel includes tankage associated with Products segment splitter at Galena Park; capacities represented on a gross basis.

b) 2024B liquids utilization reflects ratio of our tankage capacity in-service to total liquids leasable capacity; API reflects tankage temporarily unavailable for lease due to scheduled inspection and repair.

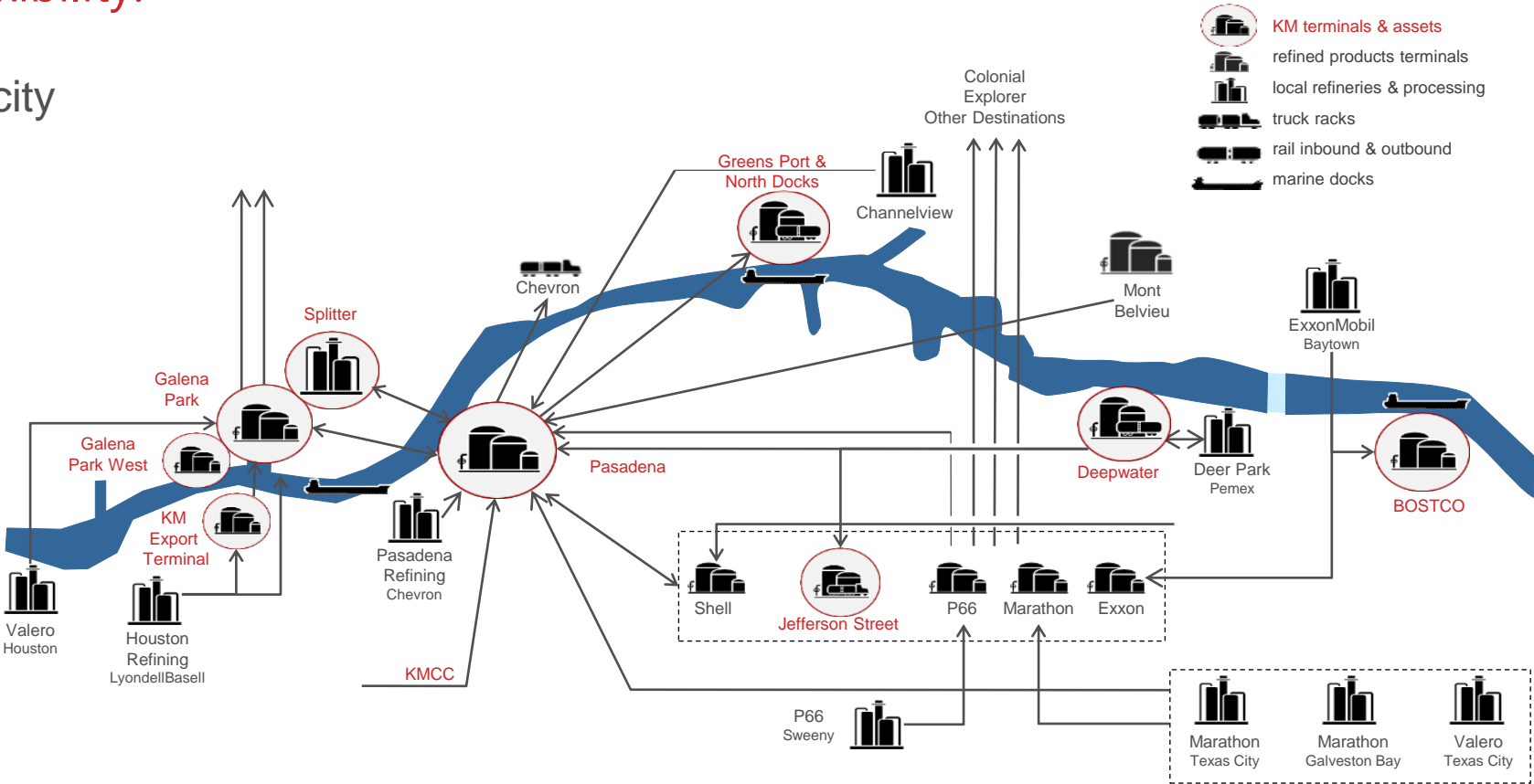
c) Principal asset (Carteret, NJ): 97% leased; 99% adjusted for API's.

# 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

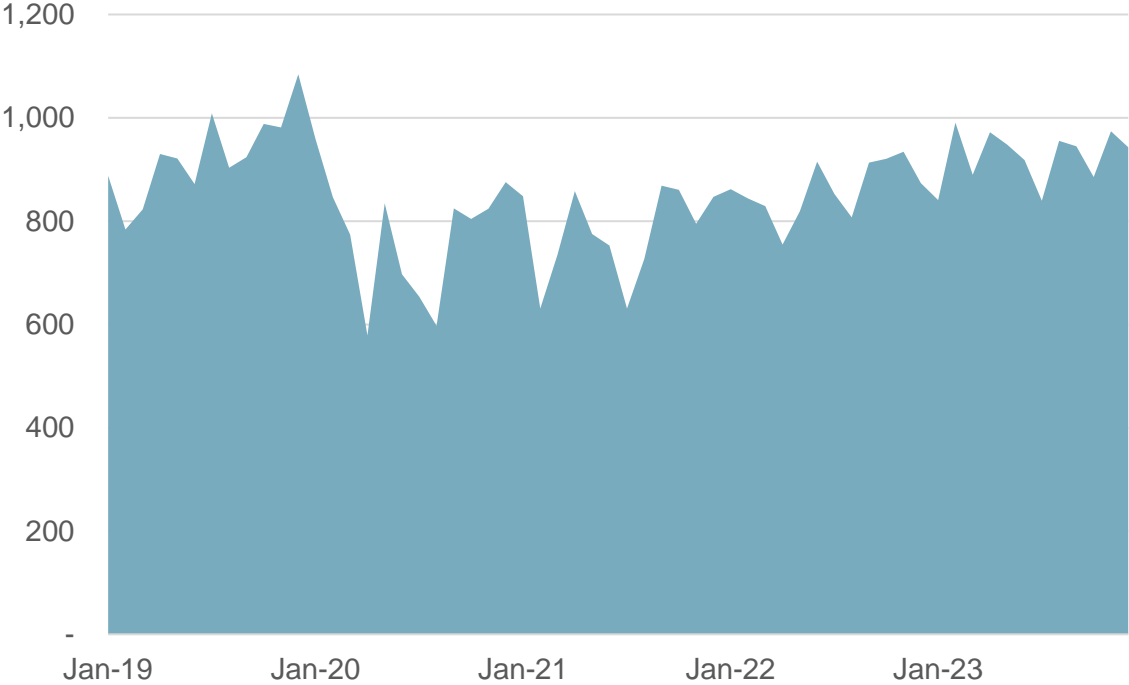


Over \$2.3 billion invested since 2010

# Leader in Clearing Advantaged USGC Gasoline & Diesel Production

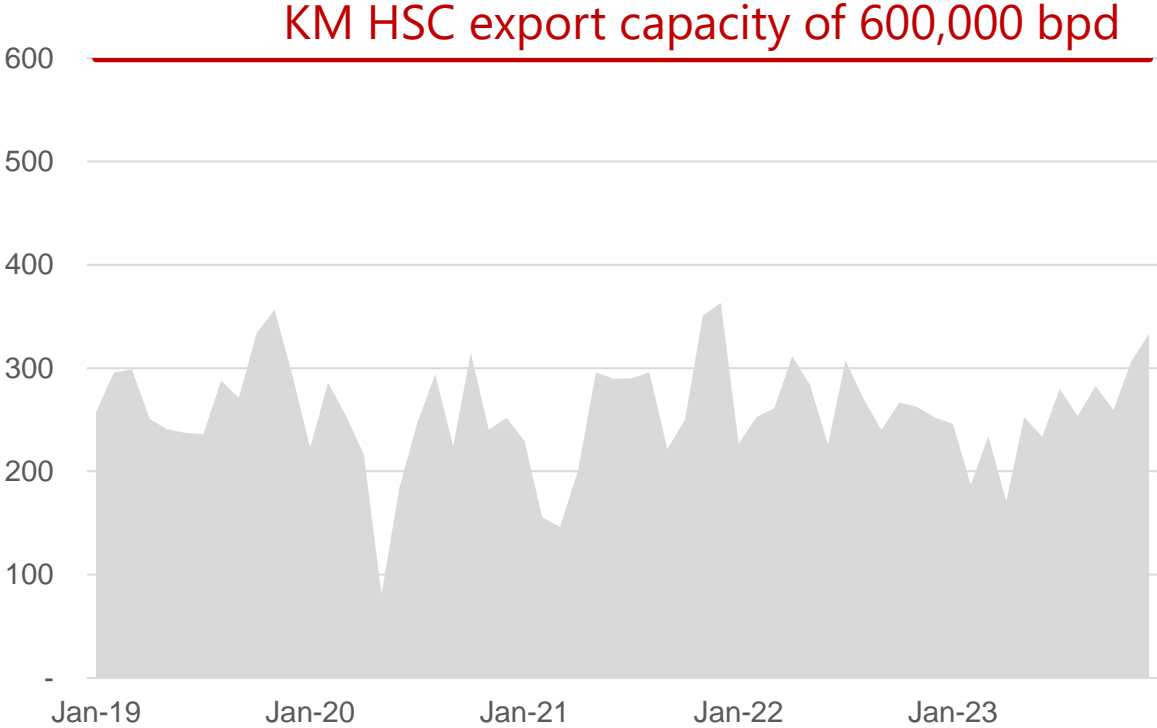
Unparalleled Optionality to Cost-Effectively Supply Both Domestic & Export Markets

KM HSC REFINED PRODUCT THROUGHPUTS TO DOMESTIC MARKETS<sup>(a)</sup> mbbld



Continued recovery in refined product throughputs alongside refinery run-rates

KM HSC REFINED PRODUCT EXPORTS<sup>(b)</sup> mbbld



Capacity available to help meet growing demand from important export markets with no capital requirements

a) Gasoline, gasoline blendstocks, diesel and jet fuel loaded outbound via Jones Act vessel, pipeline, or truck.  
 b) Gasoline, gasoline blendstocks, diesel and jet fuel exported via marine vessel & railcar.

# Tankers Meeting Domestic Maritime Demand

## Largest Jones Act Tanker Fleet and Most Efficient Vessels

### American Petroleum Tankers

- 16 fuel-efficient Jones Act tankers
- Largest fleet with the most modern vessels; average age of 9.8 years

### Jones Act fundamentals are strong

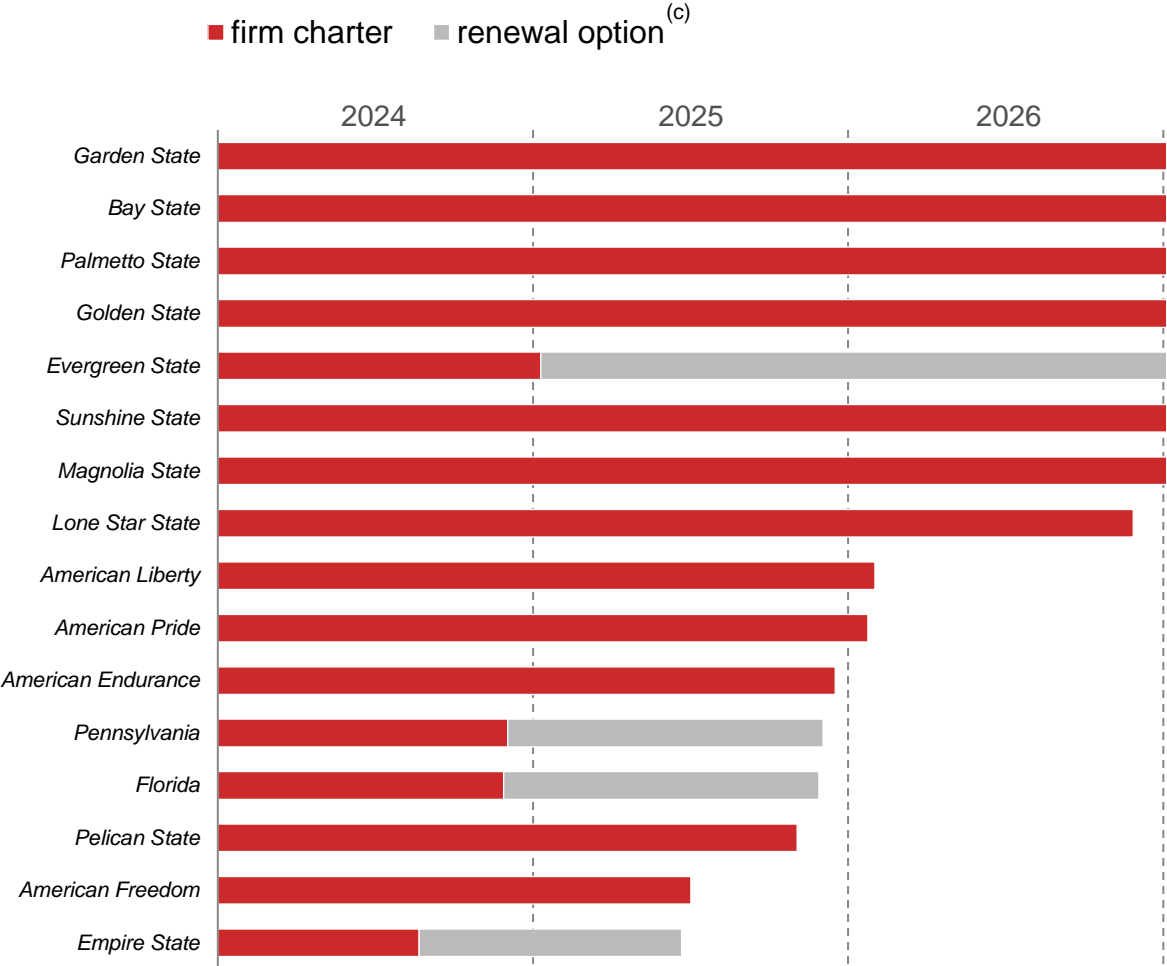
- 100% of fleet is utilized under favorable market fundamentals
- Increased demand with renewable diesel growth
- Florida refined product demand remains strong
- Global maritime emission regulations favor KMI's efficient vessels over older vessels
- Political support remains firm

### Rate upside for vessels upon renewal

- Spot time charter rates for Medium Range (MR) Jones Act tankers are in the \$80'sK/day<sup>(a)</sup>
- New-build MR capital cost >\$200MM/vessel with earliest potential deliveries in 2027<sup>(a)</sup>; would require term charter rate of >\$100K/day<sup>(a)</sup> to underwrite

### APT charter profile has little near term risk and will benefit from an increasing rate environment

	% of Vessel Days Under Charter <sup>(b)</sup>		
	2024	2025	2026
Firm	96%	71%	43%
With Likely Options	100%	92%	50%



Average firm charter term remaining is 3 years

a) Source: Wilson Gillette Report, December 2023 by Navigistics Consulting.  
 b) Revenue Days calculated as 16 vessels x 365 days, adjusted for scheduled dry docks.  
 c) Majority of option days are US Gov't contracts which are restricted to one-year terms.

# Industry-Leading Renewable Feedstock Storage & Logistics Offering

Leveraging Existing Assets to Grow Our Renewable Feedstock Capabilities



> 1,600 mbb of capacity leased for renewable feedstock storage across our network<sup>(a)</sup>

## One of the largest handlers of renewable feedstocks

- Utilizing existing assets towards capital-efficient, attractive-returning projects supporting the growing renewable fuels market
- Handle renewable feedstocks & fuels at several locations across our network
- Investing ~\$135mm to expand our Lower Mississippi River Hub (New Orleans)
- Advantaged network provides customers with flexible transportation options via rail, truck, vessel, and pipeline

a) Includes tanks under construction

# Reducing CO<sub>2</sub> Emissions on Houston Ship Channel

Added 5 Vapor Recovery Units at Galena Park & Pasadena terminals

- \$64 million
- Placed into service in 4Q 2023

Expect project to reduce Scope 1 & 2 emissions by ~34,000 metric tonnes CO<sub>2</sub>e per year, or ~38% from 2019<sup>(a)</sup>

– Equivalent to CO<sub>2</sub> emissions from:

3,860,547  
gallons of gasoline  
consumed



37,920,818  
pounds of coal  
burned



6,232  
homes' electricity  
use for one year



## Potential future opportunities

- 89 VCUs in operation today across Products & Terminals segments
- 47 VRUs in place today
- Continue to evaluate economic opportunities for additional VRU installations



Note: CO<sub>2</sub> emissions equivalent per EPA GHG calculator. The emission reduction estimate of 34,309 tonnes CO<sub>2</sub>e was calculated utilizing the GHG Project Evaluation project tool to include an evaluation of both Scope 1 and Scope 2 emissions. This differs, primarily, from the previously reported estimate of 17,500 tons CO<sub>2</sub>e because the number of VCU replacements increased in the updated estimate and waste gas was included in the updated estimate.  
a) Assumes VCUs will be used 25% of the time as backup.

# Terminals Throughput & Tonnage Statistics

2023 to 2024B Comparison

## Liquids Throughput

	Throughput		Variance vs. 2023	
	2023	2024B	MMBbls	%
<i>MMBbls</i>				
Gasoline	508.2	496.7	(11.5)	-2%
Distillate	125.0	120.5	(4.5)	-4%
Petroleum Feedstocks	42.1	43.6	1.5	4%
Renewables	52.6	53.6	1.0	2%
Chemical	39.1	41.8	2.7	7%
Vegetable Oils	5.0	11.5	6.5	130%
Other	3.1	3.5	0.4	13%
	<b>775.1</b>	<b>771.2</b>	<b>(3.9)</b>	<b>-1%</b>
<i>Liquids leased capacity %<sup>(a)</sup></i>	93.6%	94.6%		

## Bulk Tonnage

	Tonnage		Variance vs. 2023	
	2023	2024B	MM Tons	%
<i>tons (millions)</i>				
Ores/Metals (Bulk)	13.3	14.2	0.9	7%
Petroleum Coke	15.2	15.5	0.3	2%
Coal	10.8	10.9	0.1	1%
Soda Ash	3.2	3.1	(0.1)	-3%
Aggregate	2.5	2.7	0.2	8%
Salt	2.0	2.3	0.3	15%
Ores/Metals (Break-Bulk)	1.7	2.0	0.3	18%
Other Bulk	1.5	1.9	0.4	27%
Fertilizers	0.9	1.0	0.1	11%
Grains	2.2	2.5	0.3	14%
	<b>53.3</b>	<b>56.1</b>	<b>2.8</b>	<b>5%</b>

Notes: Excludes volumes shipped through Jones Act tankers. Volumes for facilities divested, idled, and/or held for sale are excluded for all periods. Petroleum feedstocks includes crude oil, black oil & refinery intermediates. Renewables include ethanol, biodiesel & renewable diesel. Vegetable Oils include renewable diesel feedstocks. Numbers will not sum due to rounding. All figures are net to KM interest.

a) Ratio of our tankage capacity in-service to total liquids leasable capacity.

CO<sub>2</sub>

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Segment Presentation

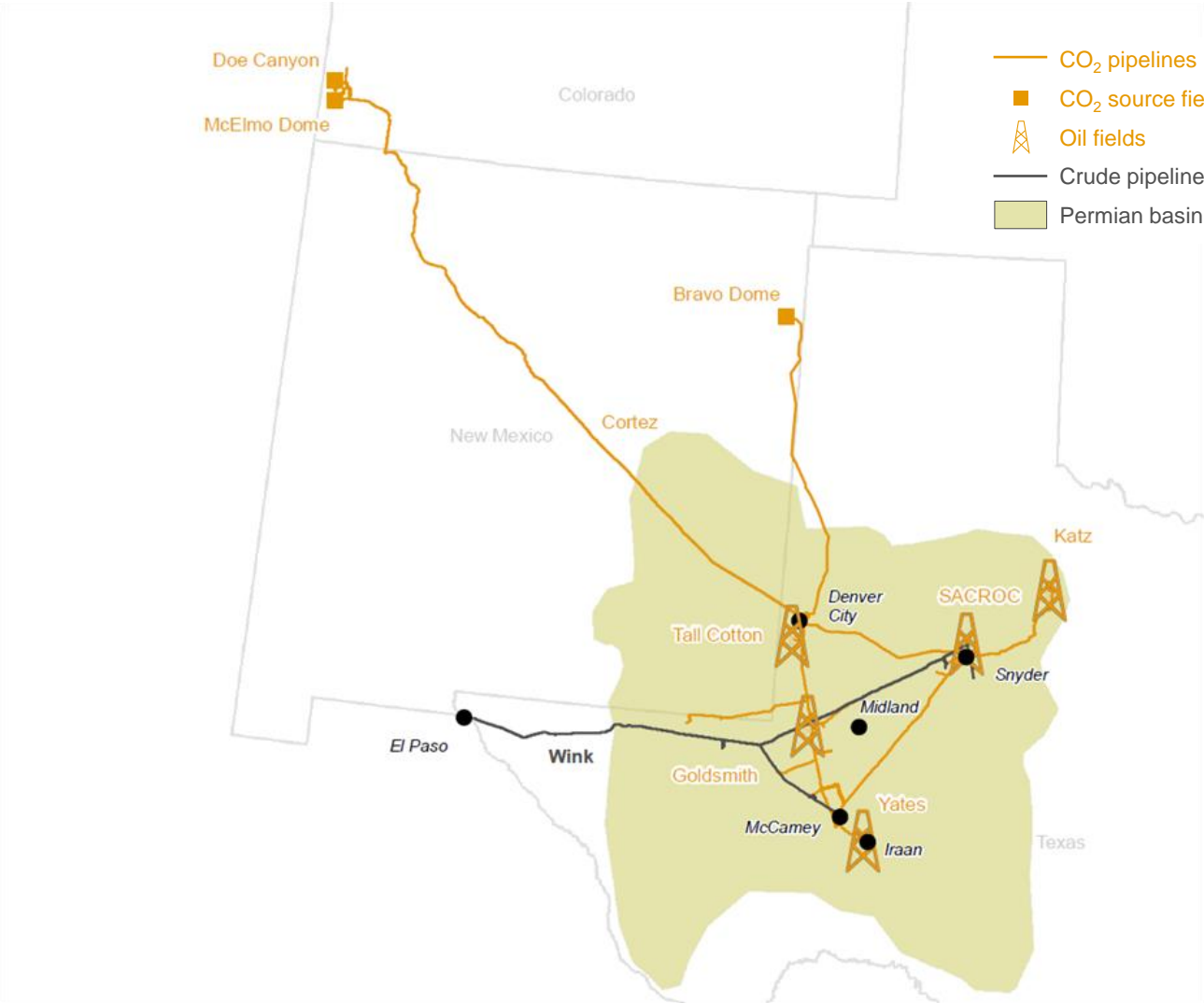
# CO<sub>2</sub> Segment Overview

World Class, Fully-Integrated Assets | CO<sub>2</sub> Source to Crude Oil Production & Takeaway in the Permian Basin

Interest in 5 oil fields with 9.3 billion barrels of Original Oil In Place

Interest in 3 CO<sub>2</sub> fields with 37 tcf of Original Gas In Place

~1,500 miles of CO<sub>2</sub> pipelines with capacity to move up to 1.5 bcfd



Note: SACROC includes Diamond M acreage.

# Enhanced Oil Recovery Process

Specializing in the Gas Injection Method of Enhanced Oil Recovery

## Three phases of oil & gas production

**PRIMARY RECOVERY**

10% OOIP recovered

Natural pressure from reservoir drives oil to pumps

**SECONDARY RECOVERY**

20-40% Cumulative OOIP recovered

Gas injection & waterflooding with goal to maintain reservoir pressure

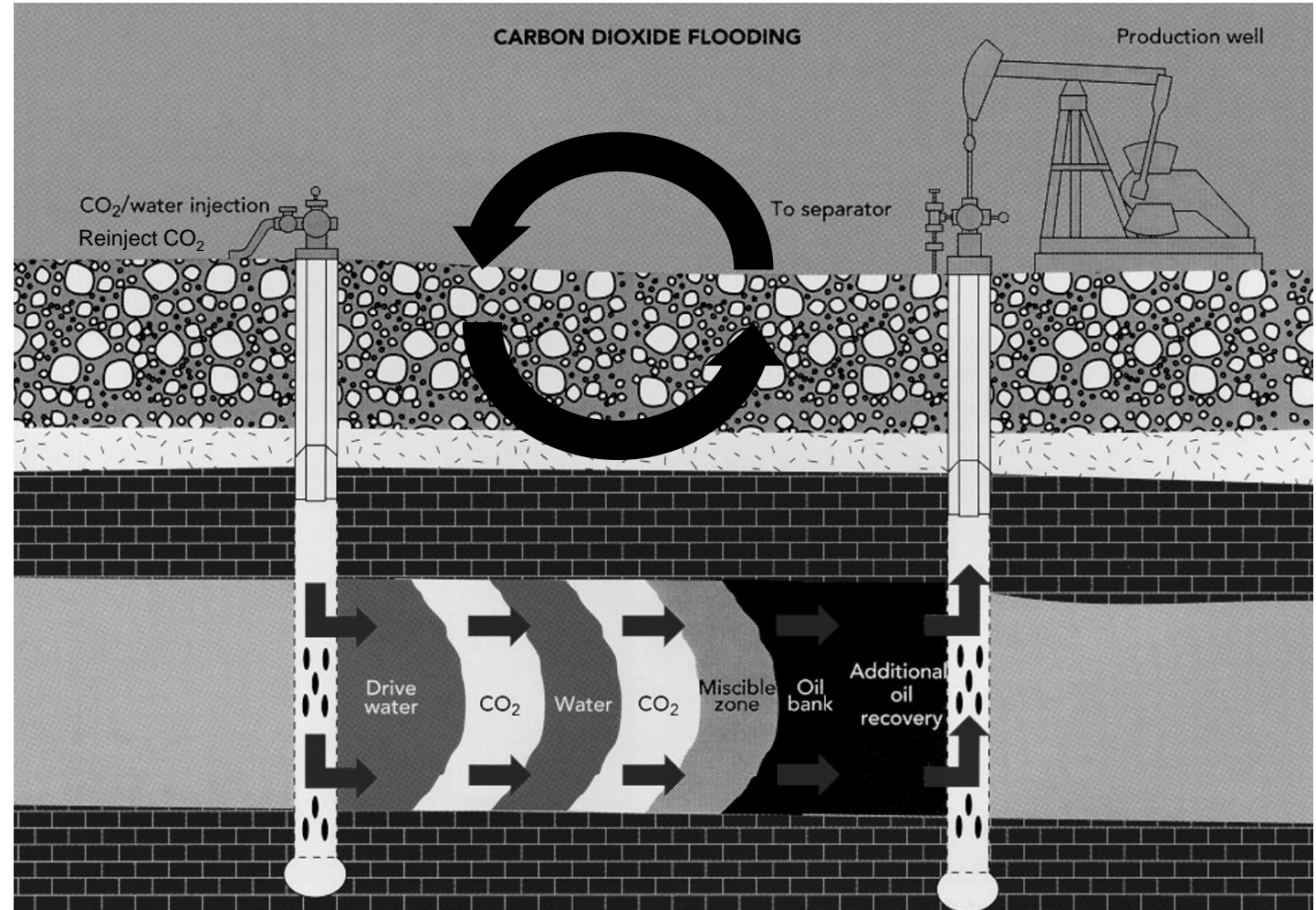
**TERTIARY (ENHANCED) RECOVERY**

30-60% Cumulative OOIP recovered

Various injection methods with goal to reduce viscosity of oil

## Methods of enhanced oil recovery

- Thermal injection – steam
  - Chemical injection – polymers, surfactants
  - Gas injection – natural gas, nitrogen, CO<sub>2</sub>
- Accounts for nearly 60 percent of U.S. EOR production



Own & operate naturally occurring CO<sub>2</sub> source, pipelines & oil fields in the Permian

# Key Factors Driving the Success of Our CO<sub>2</sub> Segment

Maximizing Returns Through Financial Discipline & Innovation



## Advantaged Assets

- Vertically integrated & Permian focused
- Produce & transport >80% of the CO<sub>2</sub> delivered into the Permian
- History of extending productive life of fields
- Positioned for carbon capture opportunities



## Highly-Skilled Team

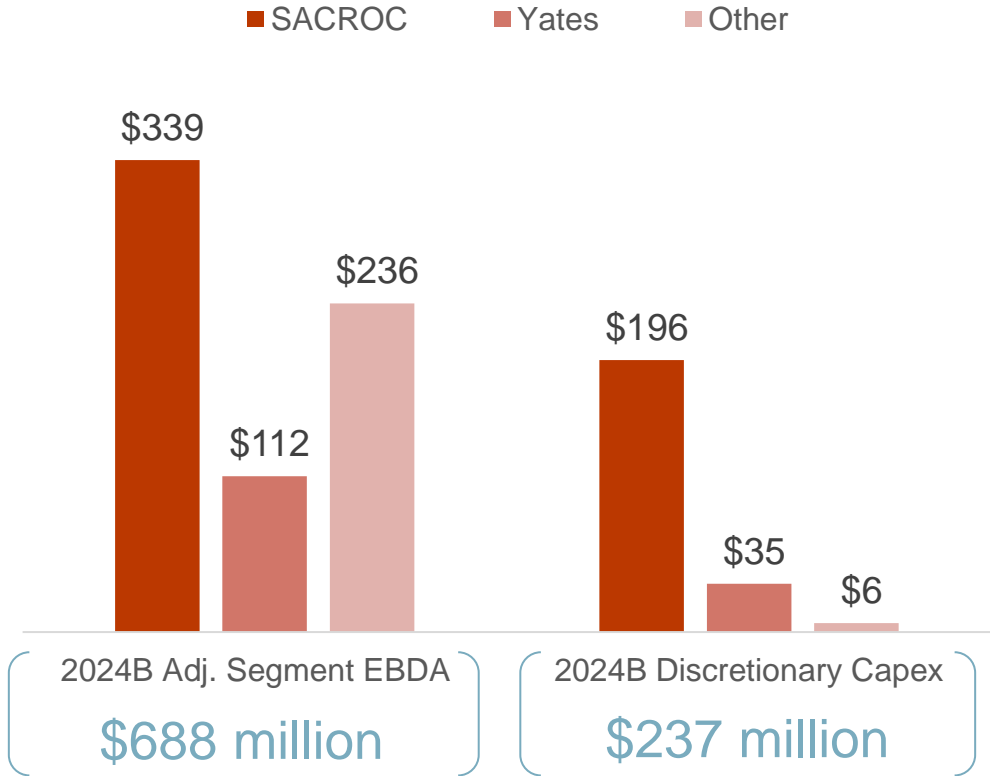
- Industry-leading experience in highly specialized business will facilitate development of CCS in North America
- Continually executing on technological advancements
- Consistently achieve production & capex budget targets
- Proven ability to adjust capital program when markets change



## Profit-Focused

- High-return asset base
- Invest based on project economics – not to maintain production
- Manage commodity price volatility with consistent hedge policy
- Healthy operating margins driven by low-cost structure
- Meaningful free cash flow & profitable through commodity cycles

# CO<sub>2</sub> EOR & Transport Budget and Sensitivities



2024B assumptions	Change	Potential Impact to Adjusted EBITDA & DCF (full year)
Crude oil & NGL production <i>37 mbbld net</i>	+/- 5% in net volumes	\$22.5 million
CO <sub>2</sub> sales <i>351 mmcf/d net</i>	+/- 5% mmcf/d in net volumes	\$7.7 million
\$82.00/bbl WTI crude oil price	+/- \$1/bbl WTI	\$5.5 million
42% NGL / crude oil price ratio	+/- 1% NGL / crude oil price ratio	\$3.3 million

## Proven capital discipline

2024B CO<sub>2</sub> EOR & Transport Free Cash Flow of \$430 million<sup>(a)</sup>

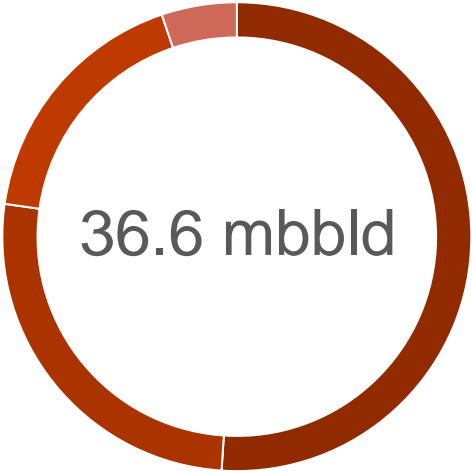
Note: Adjusted Segment EBDA, CO<sub>2</sub> EOR & Transport Free Cash Flow, Distributable Cash Flow (DCF), and Adjusted EBITDA are non-GAAP measures. See Non-GAAP Financial Measures & Reconciliations. Individual components of 2024B EBDA do not sum to \$688 million due to rounding. SACROC includes Diamond M acquisition.

a) 2024B capex includes \$237 million discretionary and \$21 million sustaining capital.

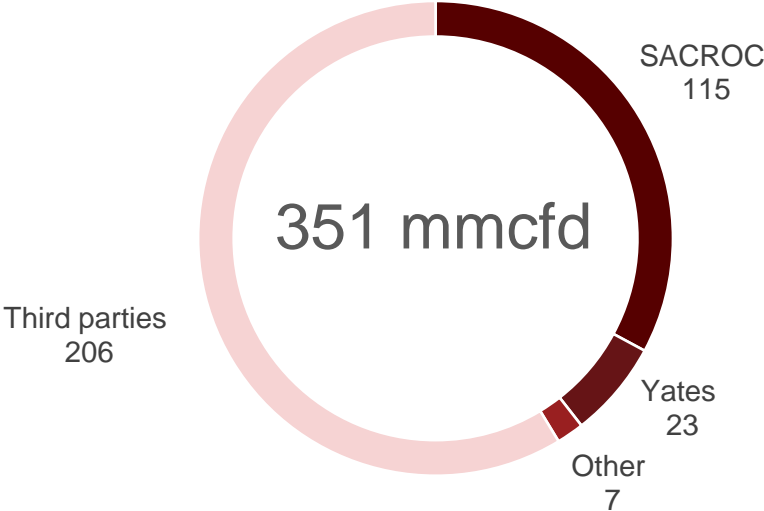
# CO<sub>2</sub> Segment Budgeted Volumes & Highlights

2024B NET OIL & NGL PRODUCTION  
mbbl/d

SACROC oil	18.7
SACROC NGL	9.6
Yates	6.4
Other	1.9



2024B NET CO<sub>2</sub> SALES  
mmcf/d



### OIL & GAS

- Majority of required takeaway capacity provided by KM-owned Wink pipeline
- ~78% of 2024B oil production hedged to WTI price

### CO<sub>2</sub> & TRANSPORT

- Supplies >80% of CO<sub>2</sub> to Permian including 100% to KM oil & gas business
- 100% of 2024B CO<sub>2</sub> production is contracted, including 84% subject to minimum volume commitments
- ~6.2 years weighted average remaining contract life with third parties

Note: SACROC includes Diamond M acquisition.

# CO<sub>2</sub> Segment 2024 Oil & Gas Major Projects

Major Projects Expected to Generate Attractive Returns

Asset	2024B capex	Commentary	Consolidated ATIRR% at WTI Price Scenarios	
			Forward Curve	\$65 Flat
SACROC	\$196mm	<ul style="list-style-type: none"> <li>— Diamond M</li> <li>— Platform 7</li> <li>— East Of Southwest Bank PH II</li> <li>— South Shore Extension</li> <li>— Southwest Centerline</li> </ul>	24%	22%
Yates	\$35mm	<ul style="list-style-type: none"> <li>— Horizontal Drain Hole Program</li> <li>— Double Displacement</li> </ul>		

Note: 2024B capex includes related CO<sub>2</sub> purchases. Forward curve strip price as of January 3, 2024.

# Extending Productive Life of Mature Fields

Innovation & Teamwork Continue to Push Out SACROC Decline

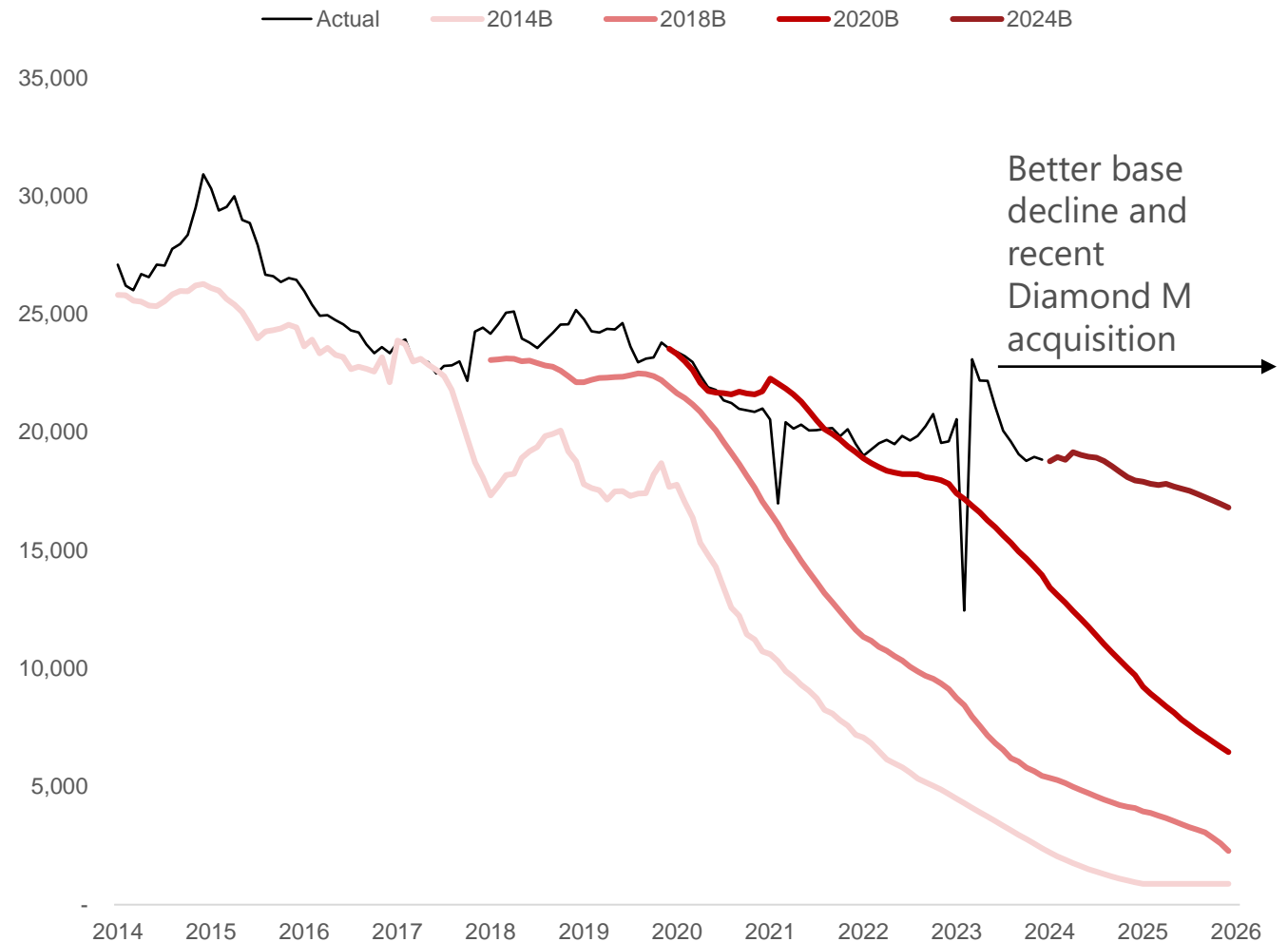
## Significant amounts of recoverable oil in place

- SACROC is estimated at 2.8 billion barrels of original oil in place (OOIP)
  - Executing Transition Zone & Conventional projects
- Evaluating other areas of the SACROC field
- Yates is estimated at 5.0 billion barrels of OOIP, representing another large resource base

## Technical expertise will drive future success

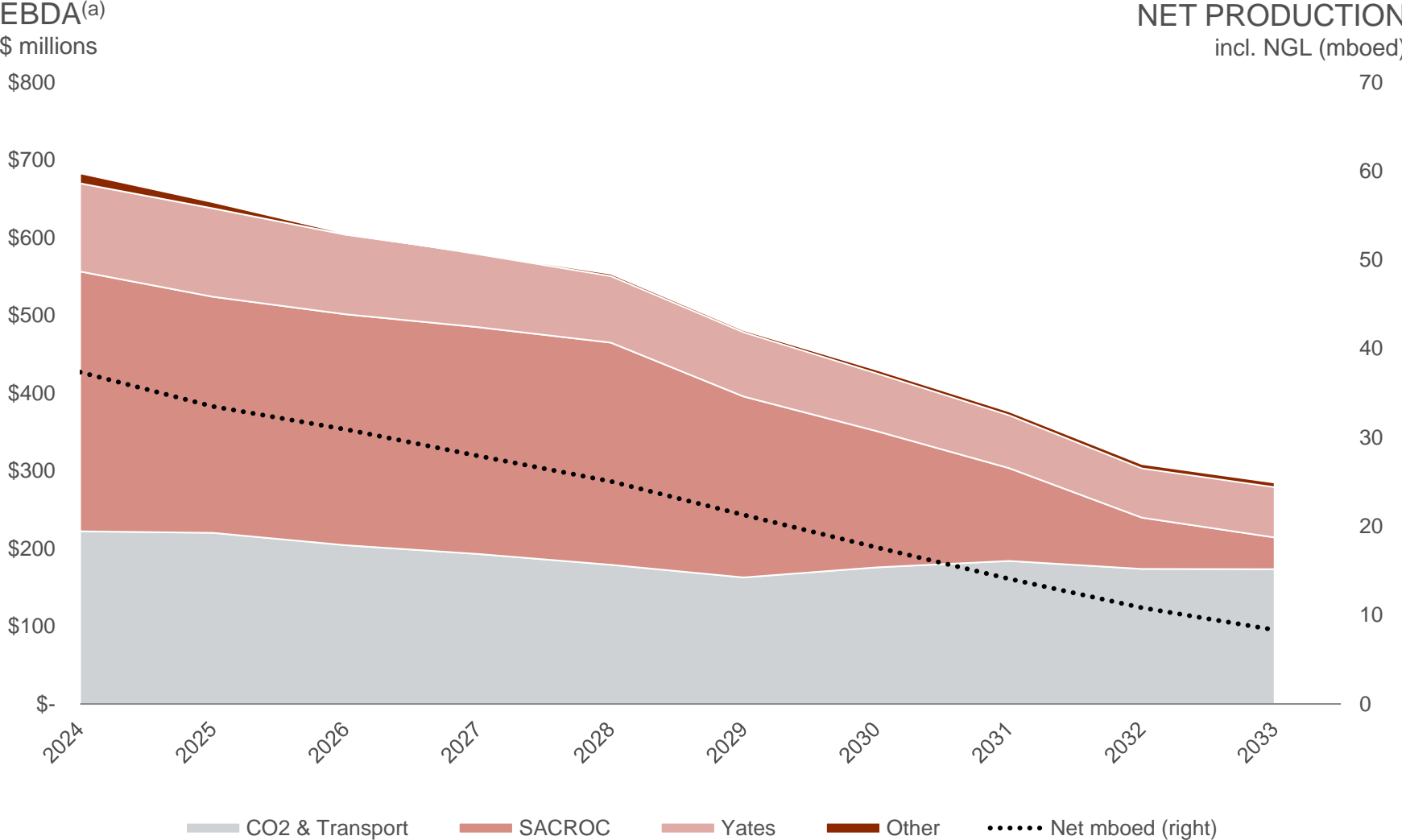
- Long track record of expanding the field through advanced technology & new exploitation techniques
- Advanced seismic reprocessing used to identify new development projects like Transition Zone
- Horizontal drilling technology has improved recovery
- Conformance technologies & techniques have led to redevelopment opportunities

SACROC NET OIL PRODUCTION FORECASTS bopd

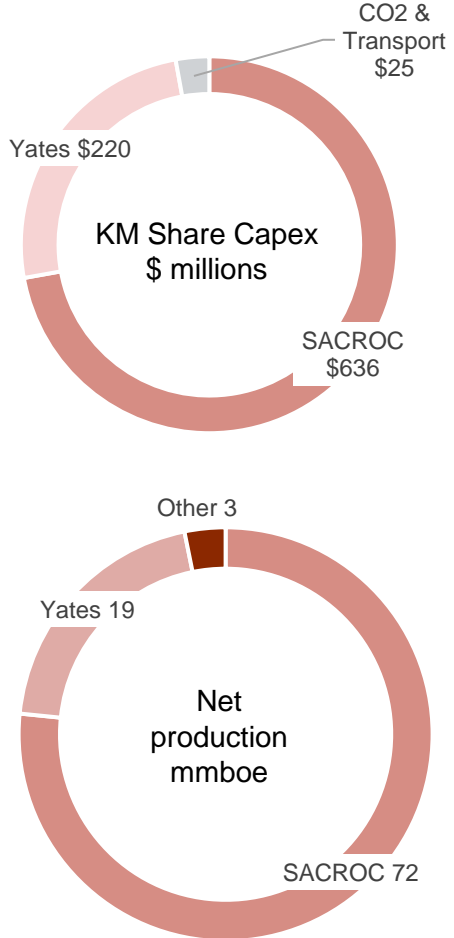


# EOR & CO<sub>2</sub> Transport Long-Term Growth Outlook

Projected Adjusted Segment EBDA, Net Production & Development Plan



10 YEAR DEVELOPMENT PLAN  
2023 – 2032

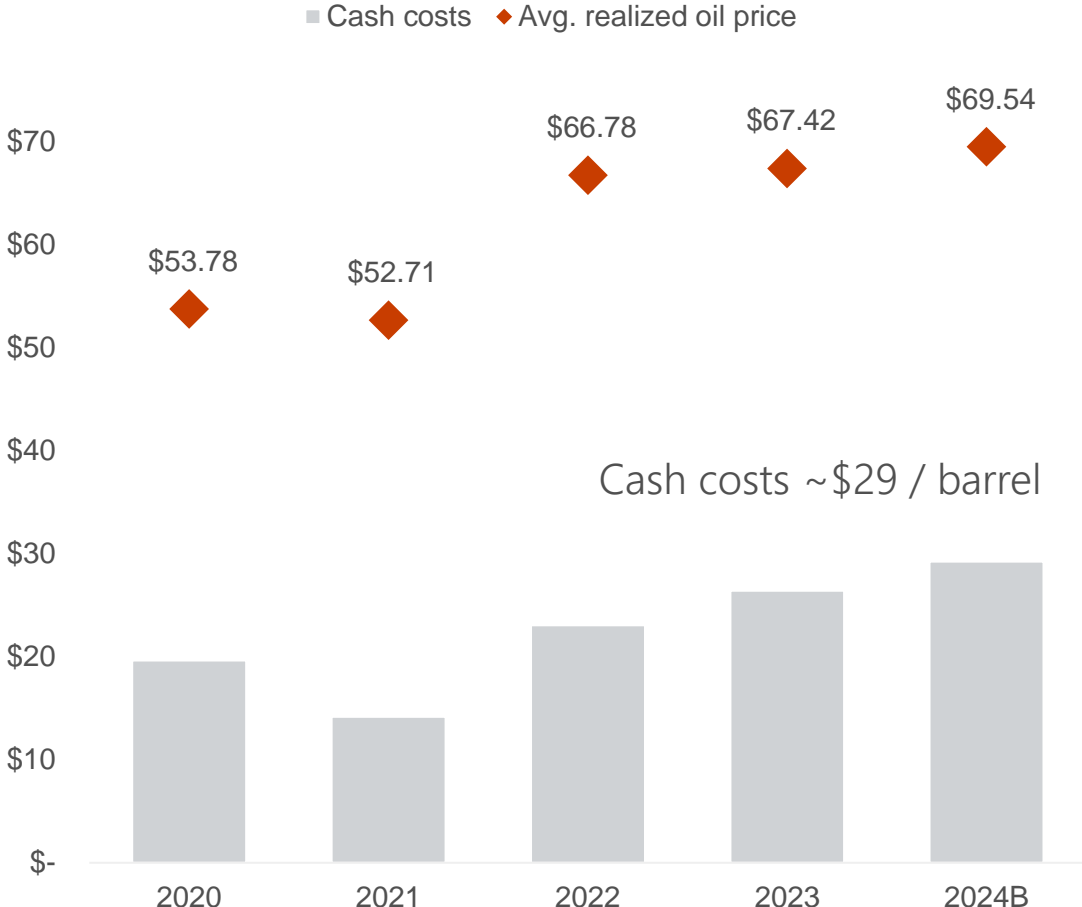


Note: Adjusted Segment EBDA is a non-GAAP measure. See Non-GAAP Financial Measures & Reconciliations. SACROC includes Diamond M acquisition.  
a) Adjusted Segment EBDA excludes intersegment eliminations related to CO<sub>2</sub> purchase profits. Assumes crude oil price of \$82.00 / bbl in 2024, \$75.00 / bbl in 2025, \$70.00 / bbl in 2026 and thereafter.

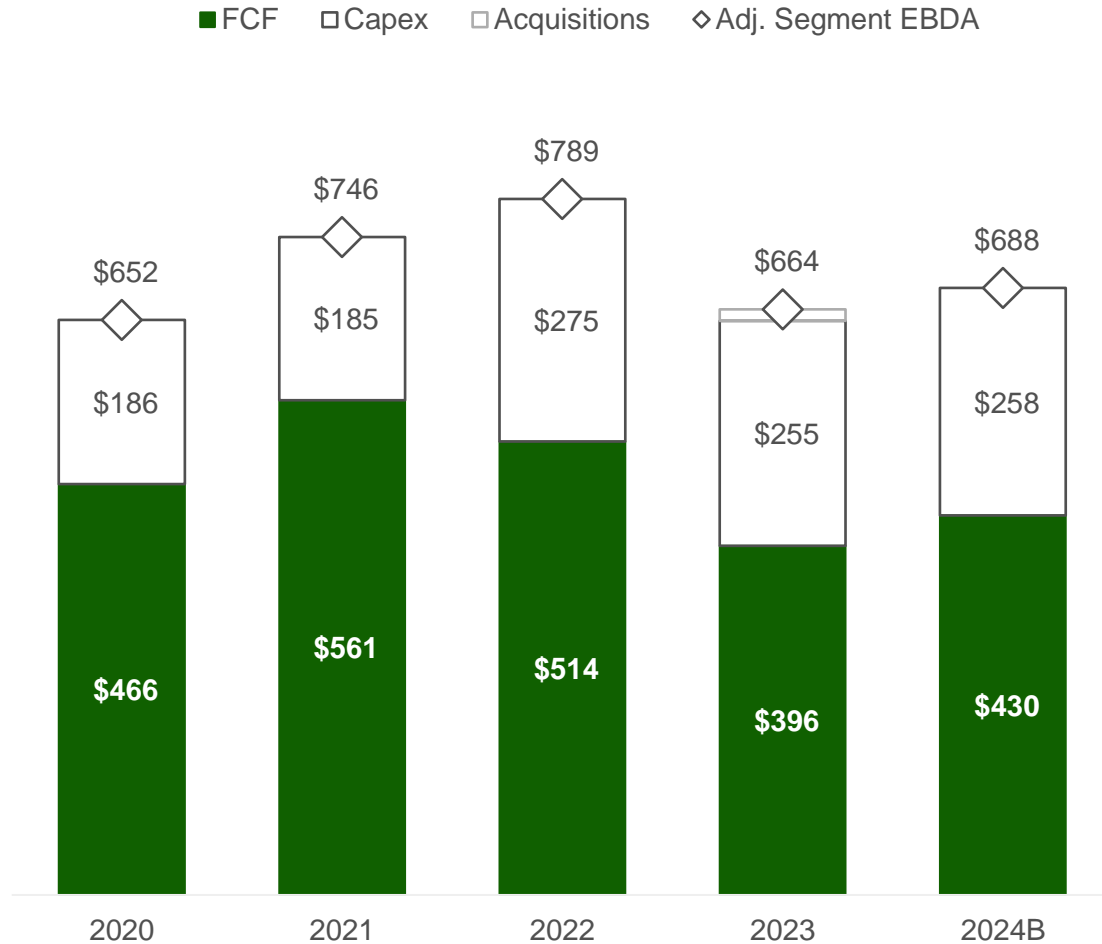
# CO<sub>2</sub> EOR & Transport Consistently Generates Free Cash Flow

Low Cash Cost Structure Yields Healthy Margins Through Commodity Price Cycles

OIL & GAS CASH OPERATING COSTS & AVG. PRICE  
\$ per net barrel



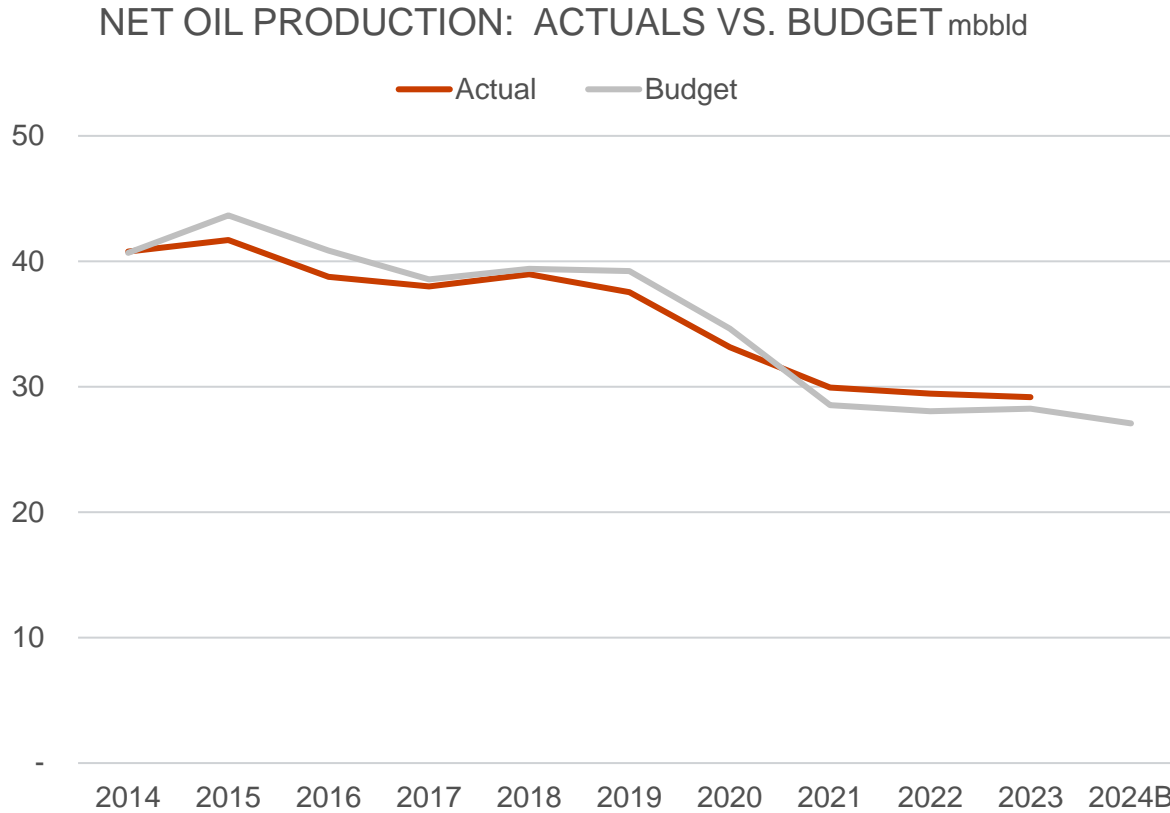
CO<sub>2</sub> EOR & TRANSPORT FREE CASH FLOW \$ millions



Note: CO<sub>2</sub> 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<sub>2</sub> 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. Higher cash costs in 2024 due to higher power costs and relative inefficiency of remaining projects.

# Predictable Volumes & Hedged Commodity Price

Mitigating Uncertainties Where Possible | EOR Oil & Gas Production Represents ~6% of KMI Business Mix



## HEDGED VOLUMES as of 12/31/2023

	2024	2025	2026	2027	2028
Crude oil - West Texas Intermediate					
\$/bbl	\$ 65.27	\$ 63.91	\$ 65.16	\$ 64.38	\$ 61.40
bbl/d	21,000	12,850	8,600	3,600	100
NGLs					
\$/bbl	\$ 51.58				
bbl/d	3,199				

Disciplined hedge policy helps mitigate volatility of expected cash flows

Stable & predictable production

# ETV Group

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## Segment Presentation

# Energy Transition Ventures (ETV) Group

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



Established a growing RNG platform and expanding opportunities in the CCS space

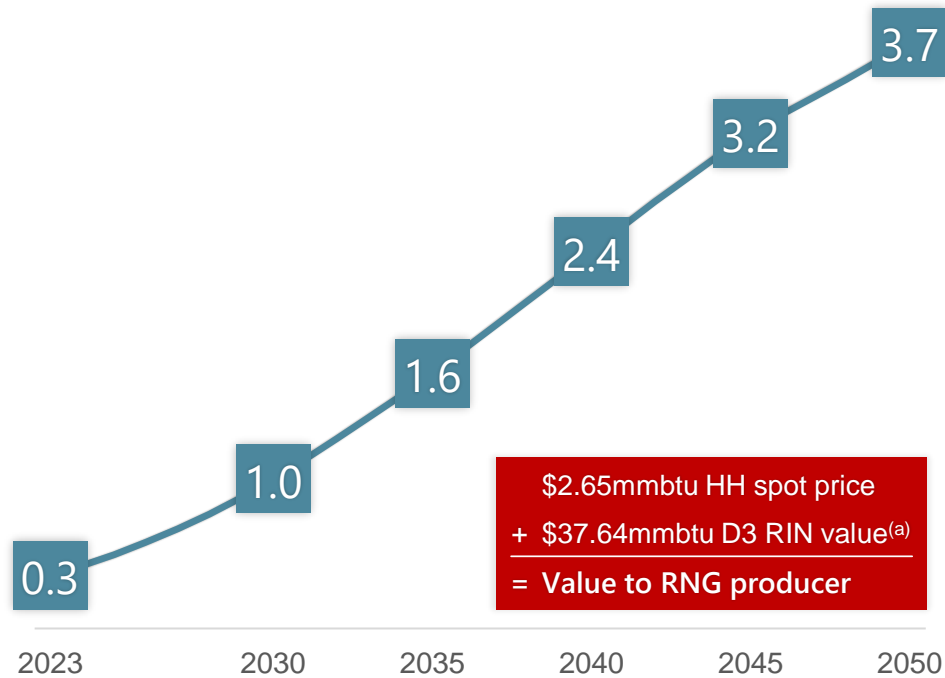
ETV Group focused on opportunities outside of our existing asset base  
Other business segments will continue to pursue their own energy transition opportunities on existing assets

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 bcf/d



Year	D3 RVO	% Change
2022	630 million	N/A
2023	840 million	33.3%
2024	1.09 billion	29.8%
2025	1.38 billion	26.6%

## TRANSPORTATION MARKET

- RNG is a low carbon, cost effective alternative to diesel
  - RNG can be delivered as Compressed Natural Gas (CNG) or Liquefied Natural Gas
  - More than 175,000 natural gas vehicles in United States, approximately 23 million worldwide
  - Advancing technology enabling wider adoption – Cummins 15L X 15N (CNG engine)
  - Natural gas vehicles 90% cleaner than EPA’s current NOx standard
  - RNG can reduce GHG emissions by up to 75% compared to diesel<sup>(b)</sup>
- Adoption supplemented by credits, RINs
  - EPA released a 3-year set rule June 21, 2023, for the Renewable Volume Obligation (RVO)
  - D3 RINs (i.e. cellulosic) are generated by fueling vehicles with RNG and are the highest and best use

## VOLUNTARY MARKET

- Continued adoption by utilities, universities, and industrials with GHG Emissions targets or mandates, with potential for substantial growth over next 10 years

RNG market has experienced tremendous growth and continues to see accelerated participation

Sources: U.S. RNG production per WoodMackenzie, North America Gas 10-Year Investment Horizon Outlook, October 2023.

a) \$3.21 2023 D3 RIN price multiplied by 11.727 to convert to \$/MMBtu. Pricing as of 1/03/2024.

b) Emissions data per the EPA.

# Growing RNG Portfolio

LANDFILL-RNG ANNUAL  
PRODUCTION CAPACITY net to KM

**5.6 bcf** operational (6.1 bcf gross)

**+0.8 bcf** expected online 2H 2024

**=6.4 bcf** (6.9 bcf gross)

Primarily contracted in transportation market today:

- Long-term contracts in transportation/RIN market
- Recent EPA rule changes provide stability & liquidity to the transportation market
- Longer-term opportunity in voluntary markets as price gap narrows

Expect first full-year Project EBITDA multiple of ~6x based on cumulative investment once all facilities are in service

Additional RNG conversion opportunities with acquired LFGE assets

6.9 bcf of RNG reduces emissions by 3.9 million metric tons CO<sub>2</sub> e per year, equivalent to:



9.1mm  
barrels of oil  
consumed

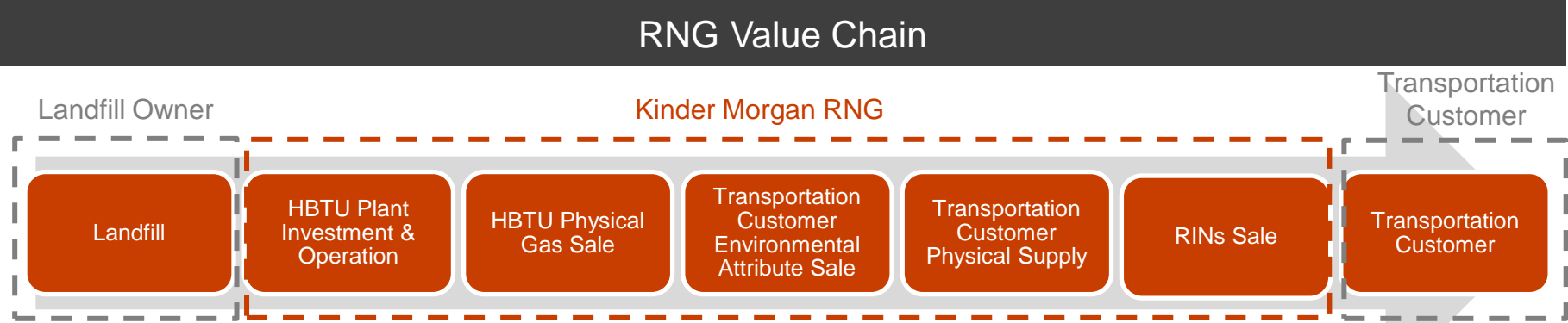


439mm  
gallons of gasoline  
consumed



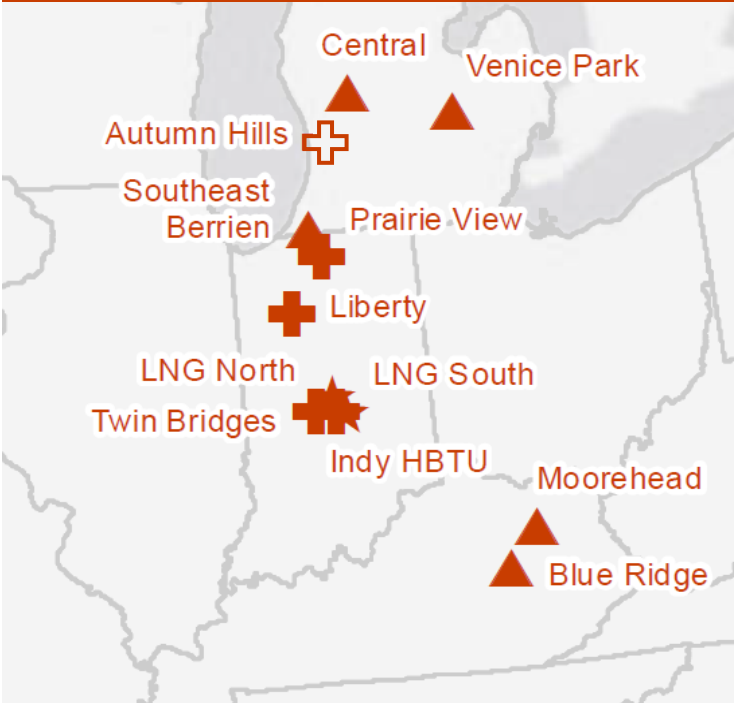
carbon sequestered  
by 4.6mm acres  
of U.S. forest

# Vertical Integration Drives Value and Growth



- Vertical integration allows KM to retain a higher margin
- Higher margins lead to more opportunities
- Direct customer relationships increase our growth potential

## Midwest



## South Central



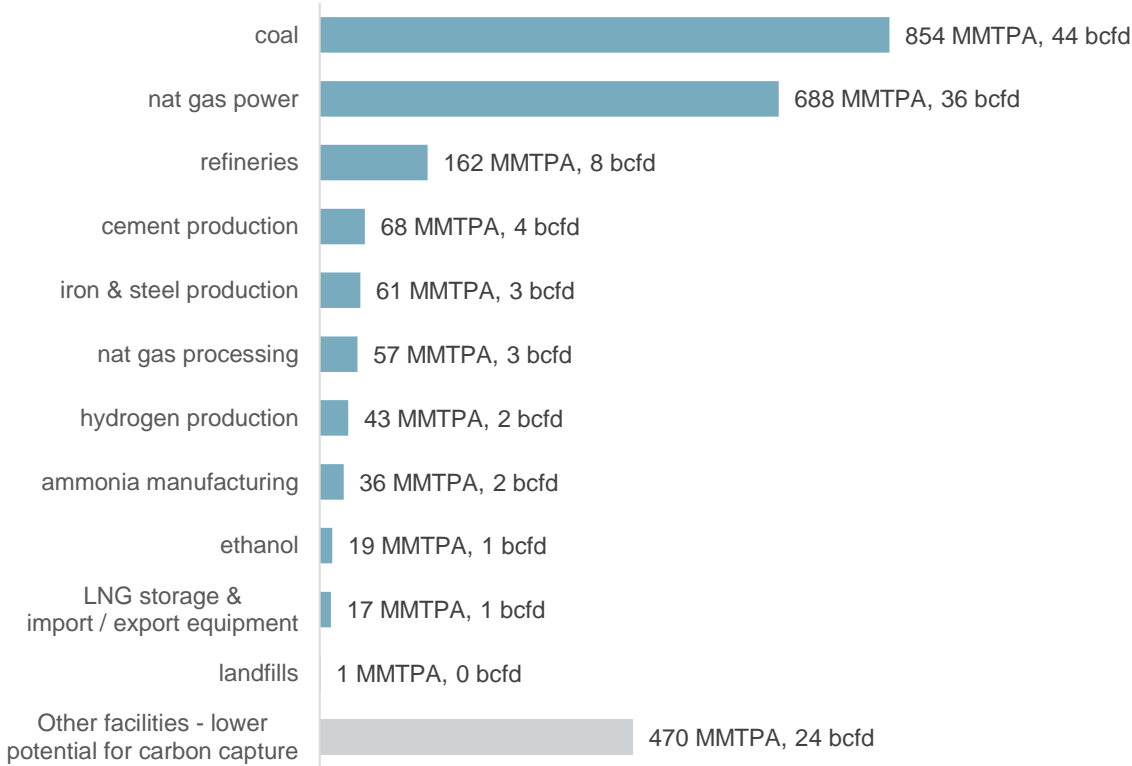
## Renewable Portfolio

- Scale to address accelerating demand for renewable energy
- Optionality across portfolio enables additional pathways to maximize value
- Synergy with KMI infrastructure provides differentiated advantage

# Growing Opportunities in CCUS Market

## IRA Improved CCS Economics

### U.S. CO<sub>2</sub> EMISSIONS FROM POINT SOURCES



~1,900 MMTPA, or ~100 bcf, CO<sub>2</sub> emissions associated with facilities that could be candidates for carbon capture  
CO<sub>2</sub> stream purity varies by facility type, impacting economics

### IRA INCREASES CCUS OPPORTUNITIES

#### KEY IRA CHANGES

#### MARKET IMPACT

Increase in 45Q credit value

Increases number of economic projects

Direct pay options

Simplifies financing structures for capture parties

Reduction in captured volume thresholds

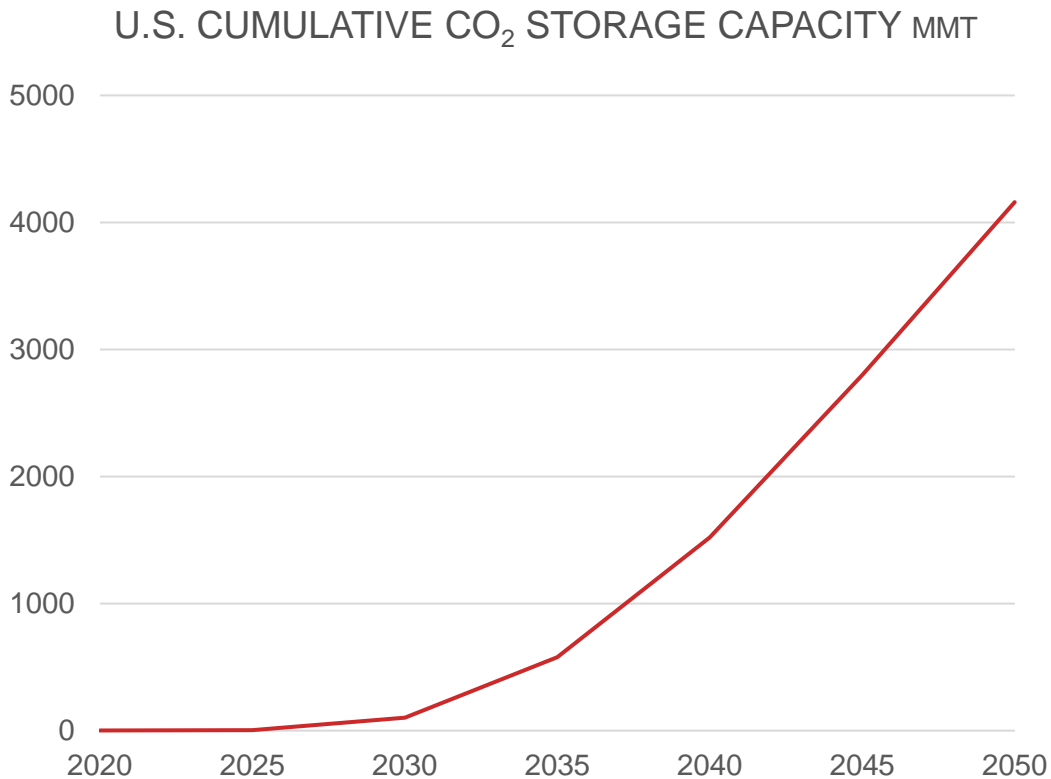
Increases number of potential projects

Date of Construction start extension

Relieves time constraint

Increasing number of CCUS opportunities from existing sources and generation of low carbon intensity fuels (i.e. blue hydrogen, SAF, ethanol, RNG, e-fuels, etc.)

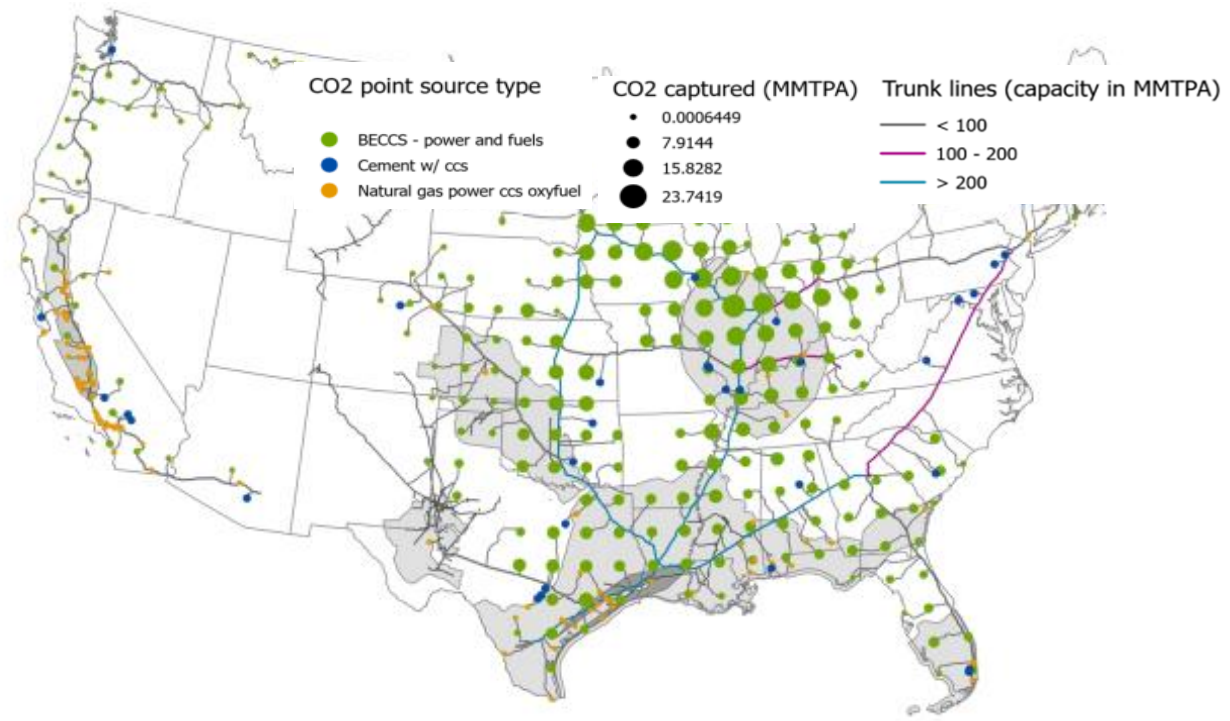
# Net-Zero Scenarios Require Carbon Capture Infrastructure Buildout



Princeton’s Net-Zero America Report estimates that CO<sub>2</sub> storage would need to increase substantially in order to progress toward climate goals, ultimately requiring significant investment & infrastructure

Source: Princeton University, Net-Zero America Report, October 2021, E-B+ Scenario.  
 Note: BECCS = Bio-Energy with Carbon Capture & Storage.

**CO<sub>2</sub> POINT SOURCES & PIPELINE INFRASTRUCTURE IN 2050**



CO <sub>2</sub> pipeline estimates by 2050	CO <sub>2</sub> storage estimates by 2050
--	---

Nearly 70,000 miles	>4 GTpa of CO <sub>2</sub> storage available
Nearly \$225 billion cumulative capital deployed	\$80 billion cumulative capital deployed

Kinder Morgan is positioned to be a leader in CO<sub>2</sub> pipeline infrastructure build out with increasing number of CCUS projects in development

# CCUS Value Chain



## Emission Sources

- In discussions with emissions sources throughout North America on CCUS solutions
- May capture emissions from our gas processing (high purity CO<sub>2</sub> source), LNG, ethanol, and landfill RNG assets



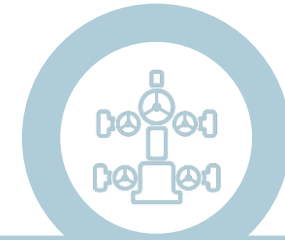
## Capture

- Evaluate opportunities to invest, construct, and/or operate
- Leverage existing capabilities including fabrication & processing expertise



## Transport

- One of the largest CO<sub>2</sub> pipeline owners in North America
- 1.5 bcf/d Cortez pipeline delivers ~80% of the CO<sub>2</sub> used for Permian EOR
- Experts at developing & constructing CO<sub>2</sub> pipeline – there are barriers to entry due to unique construction & design of CO<sub>2</sub> pipe
- Potential to convert pipeline in certain situations



## EOR / Sequestration

- Substantial EOR experience
- EOR can benefit from 45Q today and can be coupled with sequestration options for enhanced optionality
- Leverage downhole CO<sub>2</sub> experience to assess sequestration locations
- Our source fields in Colorado have longer-term potential for sequestration

Uniquely positioned to participate across the value chain based on project and counterparty needs

# West Texas CCUS

Utilizing KM's Assets and Expertise to Enable Accretive CCS Projects

## Red Cedar

- 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
- 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<sub>2</sub> and deliver the captured CO<sub>2</sub> to Kinder Morgan's existing Cortez pipeline, and ETV will transport and permanently sequester the CO<sub>2</sub> in a Class II well in the Permian Basin
- Received MRV from EPA, waiting on approval of Class II permit modification from RRC
- Net capital investment of less than \$50 million
- Target in-service by Q4 2024

## Additional Opportunities

- KM ETV is pursuing additional growth opportunities that complement the existing CO<sub>2</sub> business
- KM is leveraging existing CO<sub>2</sub> assets, which remains the largest contiguous capacity CO<sub>2</sub> pipeline network in the US, to offer efficient transport and sequestration solutions to emitters
- Looking at Class VI opportunities around existing CO<sub>2</sub> infrastructure

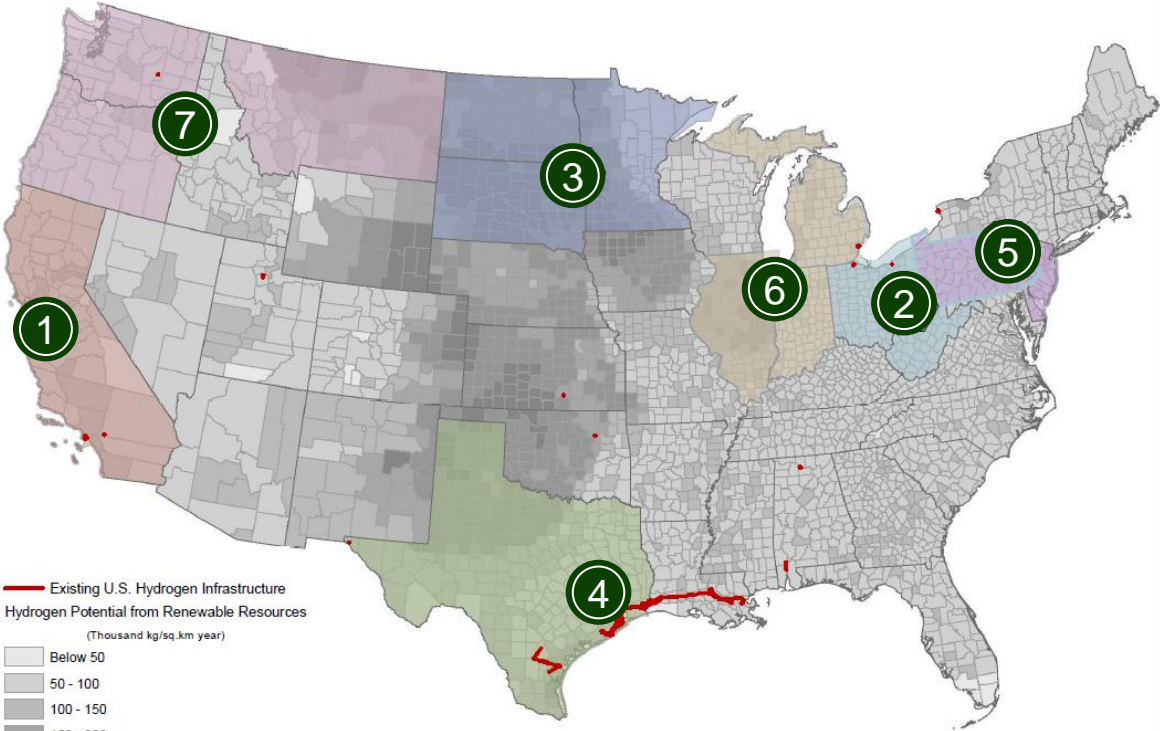


# Midstream Opportunities in a Growing Clean Hydrogen Economy

The Clean Hydrogen Market Remains Nascent, Yet Infrastructure Buildout Will be Crucial to its Growth

- **Meaningful market growth likely to require significant government subsidies and action along with greater public and private capital investment**
  - Demand growth driven by European & Asian incentives, while U.S. incentivizing supply
  - Midstream solutions will be paramount for broader market expansion
  - Incentives for incremental midstream development of clean hydrogen infrastructure could become a significant market catalyst
- **The cost of delivered clean hydrogen likely to remain relatively expensive until significant incremental infrastructure can be built out**
  - Significant challenges exist when attempting to safely blend hydrogen molecules into existing natural gas infrastructure, warranting an emphasis on newbuild hydrogen infrastructure
- **Incremental development of new clean hydrogen infrastructure projects have potential to generate significant, stable long-term dedicated cash flow streams for decades to come**
- **U.S. Gulf Coast has significant growth potential**
  - Strategic commercial location adjacent to favorable natural resources (geology for CO<sub>2</sub>/hydrogen storage, wind/solar for green hydrogen production) with significant infrastructure advantages and global export potential
- **Kinder Morgan expects to leverage its leadership position in transportation, storage and terminalling services, including its decades of experience in moving and storing CO<sub>2</sub> and natural gas, to be a leading midstream service provider in a growing clean hydrogen economy**

## U.S. RENEWABLE HYDROGEN POTENTIAL AND EXISTING INFRASTRUCTURE



Hub	Projects Selected by the U.S. Department of Energy	States	Proposed Funding
1	Alliance for Renewable Clean Hydrogen Energy Systems	CA	Up to \$1.2 Billion
2	Appalachian Regional Clean Hydrogen Hub	OH,PA,WV	Up to \$925 Million
3	Heartland Regional Hub	MN,ND,SD	Up to \$925 Million
4	HyVelocity Hub	TX	Up to \$1.2 Billion
5	Mid-Atlantic Clean Hydrogen Hub	DE,NJ,PA	Up to \$750 Million
6	Midwest Alliance for Clean Hydrogen Hub	IN,IL,MI	Up to \$1 Billion
7	Pacific Northwest Hydrogen Hub	MT,OR,WA	Up to \$1 Billion

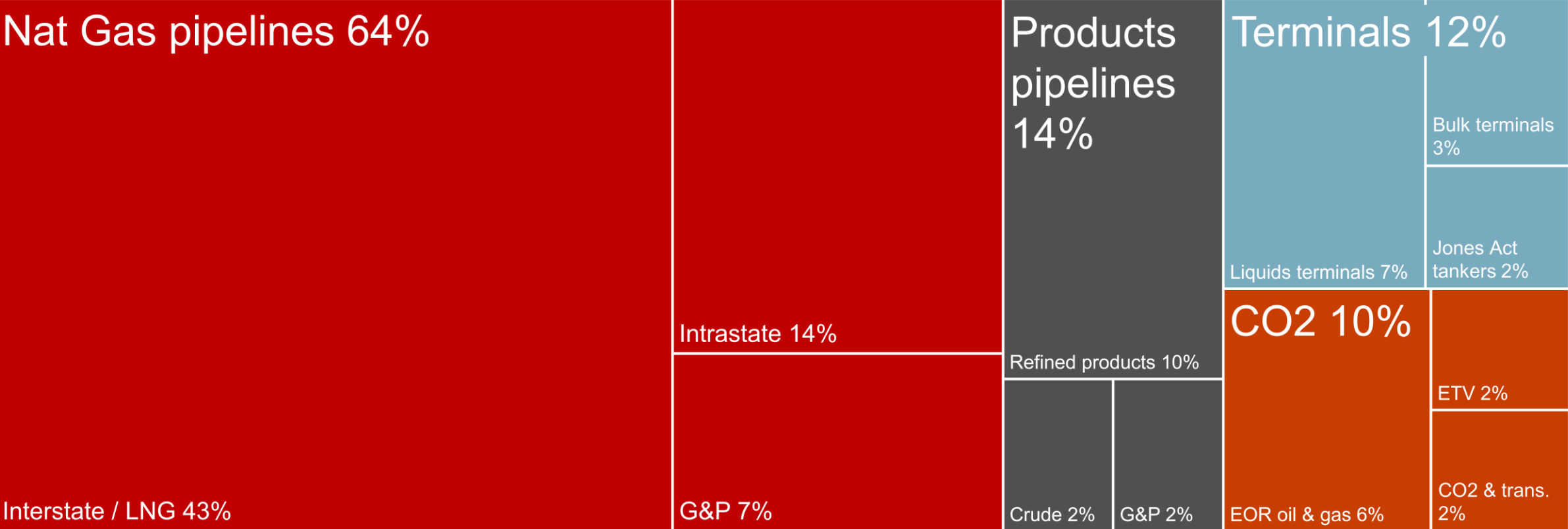
Kinder Morgan is well positioned to be a market leader in clean hydrogen infrastructure

# CORPORATE ITEMS

*Pig Launcher on EPNG, Flagstaff, Arizona*

# Business Mix

Leading Infrastructure Provider Across Multiple Critical Energy Products



Note: Business mix based on 2024 budgeted Total Adjusted Segment EBDA (a non-GAAP measure). See Non-GAAP Financial Measures & Reconciliations.

# Contract Strategy Insulates Cash Flow Through Commodity Cycles

Structure Long-Term Contracts That Minimize Price & Volume Volatility

	2024B Total Adjusted Segment EBDA:	Take-or-pay or hedged Volumes & price are contractually fixed	Fee-based Price is fixed, volumes are variable	Commodity-price based	Avg. remaining contract life as of 1/1/2024	Additional cash flow security
Natural Gas	Interstate / LNG	39%	4%		6.2 / 16.7 years	Tariffs are FERC-regulated
	TX Intrastate	12%	2%		6.7 years	
	G&P	1%	5%	1%	3.5 years	Primarily acreage dedications for fee-based contracts
Products	Refined products	1%	8%	1%	generally not applicable	Pipeline tariffs are FERC-regulated
	Crude transport	1%	1%		1.9 years	~60% of 2024B Products Segment Adj. Segment EBDA has an annual inflation-linked tariff escalator
	Crude G&P		2%			
Terminals	Liquids terminals	5%	2%		2.4 years	~73% of 2024B 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%			3.0 years	
	Bulk terminals	1%	2%		3.8 years	
CO <sub>2</sub>	EOR Oil & Gas	5%		1%		Commodity-price based contracts are mostly minimum volume committed
	CO <sub>2</sub> & Transport	1%	1%		6.2 years	
	ETV			2%		
		<b>68%</b>	<b>27%</b>	<b>5%</b>		

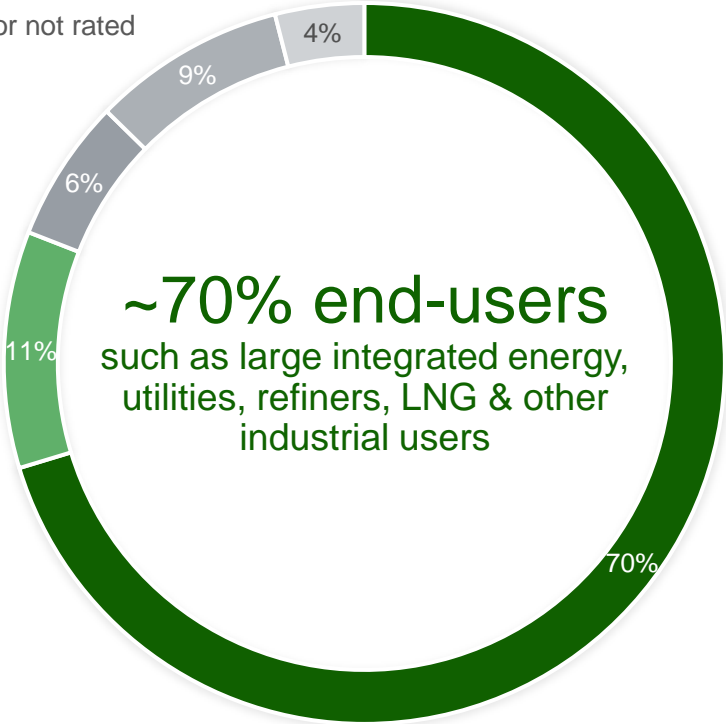
Note: Total Adjusted Segment EBDA is a non-GAAP measure. See Non-GAAP Financial Measures & Reconciliations. TX Intrastate average remaining contract life includes term sale portfolio.

# Customers Are Primarily End-Users of the Products We Handle

Net Revenues Underpinned by Investment Grade Counterparties & Credit Support | Ratings as of January 9, 2024

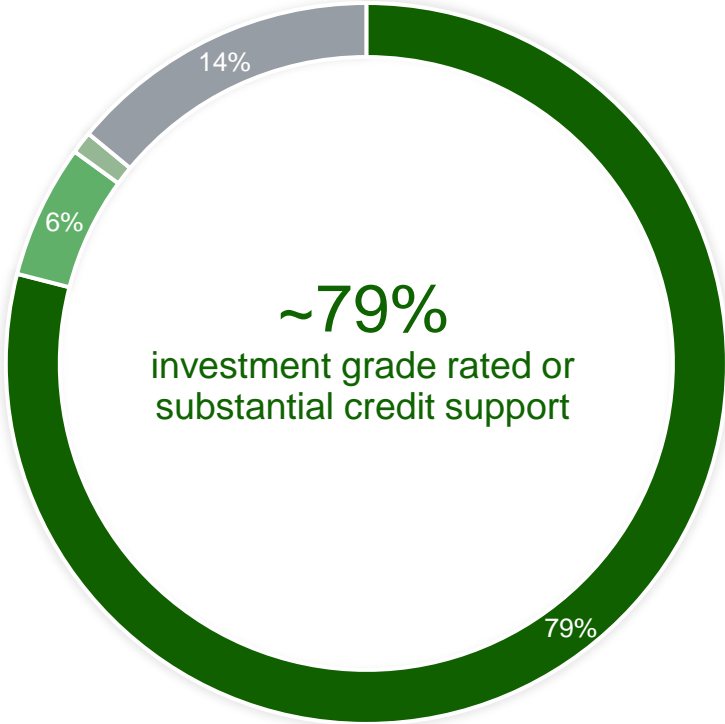
**CUSTOMER TYPE**

- End-user
- Producer - IG or substantial credit support
- Producer - non-IG or not rated
- Midstream
- Marketer



**CREDIT RATING**

- IG or substantial credit support
- BB+ to B
- B- or below
- Not rated



**<1% of customers are B- or lower rated after collateral & remarketing efforts**

Note: Based on 2024 budgeted net revenues (a non-GAAP measure), which include our share of unconsolidated joint ventures & net margin for our Texas Intrastate customers & other midstream businesses. Pie charts include 245 customers >\$5mm at their respective company credit ratings per S&P, Moody's & Fitch, shown at the S&P-equivalent rating & utilizing a blended rate for split-rated companies, which represent ~85% of total net revenues.

# 2024 Budget Sensitivities

## Limited Overall Commodity Exposure

2024B assumptions	Change	Potential Impact to Adjusted EBITDA & DCF (full year)				
		Natural Gas	Products	Terminals	CO <sub>2</sub>	Total
Natural gas G&P volumes 3,934 bbtud	+/- 5%	\$34 million				\$34 million
Refined products volumes (gasoline, diesel & jet fuel) 1,675 mbbld for Products segment	+/- 5%		\$40 million	\$12 million		\$52 million
Crude oil & NGL production volumes 37 mbbld net	+/- 5% in net volumes				\$22.5 million	\$22.5 million
\$82.00/bbl WTI crude oil price	+/- \$1/bbl WTI	\$1.4 million	\$1.1 million		\$5.5 million	\$8.0 million
\$3.50/Dth natural gas price	+/- \$0.10/Dth	\$1.0 million <sup>(a)</sup>			\$0.4 million	\$1.4 million <sup>(a)</sup>
NGL / crude oil price ratio 48% in Natural Gas segment & 42% in CO <sub>2</sub> segment	+/- 1% price ratio	\$1.1 million			\$3.3 million	\$4.4 million
\$3.45/RIN D3 RIN price	+/- \$0.10/RIN				\$4.7 million	\$4.7 million
<b>Potential Impact to DCF (balance of year)</b>						
SOFR rate: 5.12%	+/-10-bp change in SOFR					\$6.0 million <sup>(b)</sup>

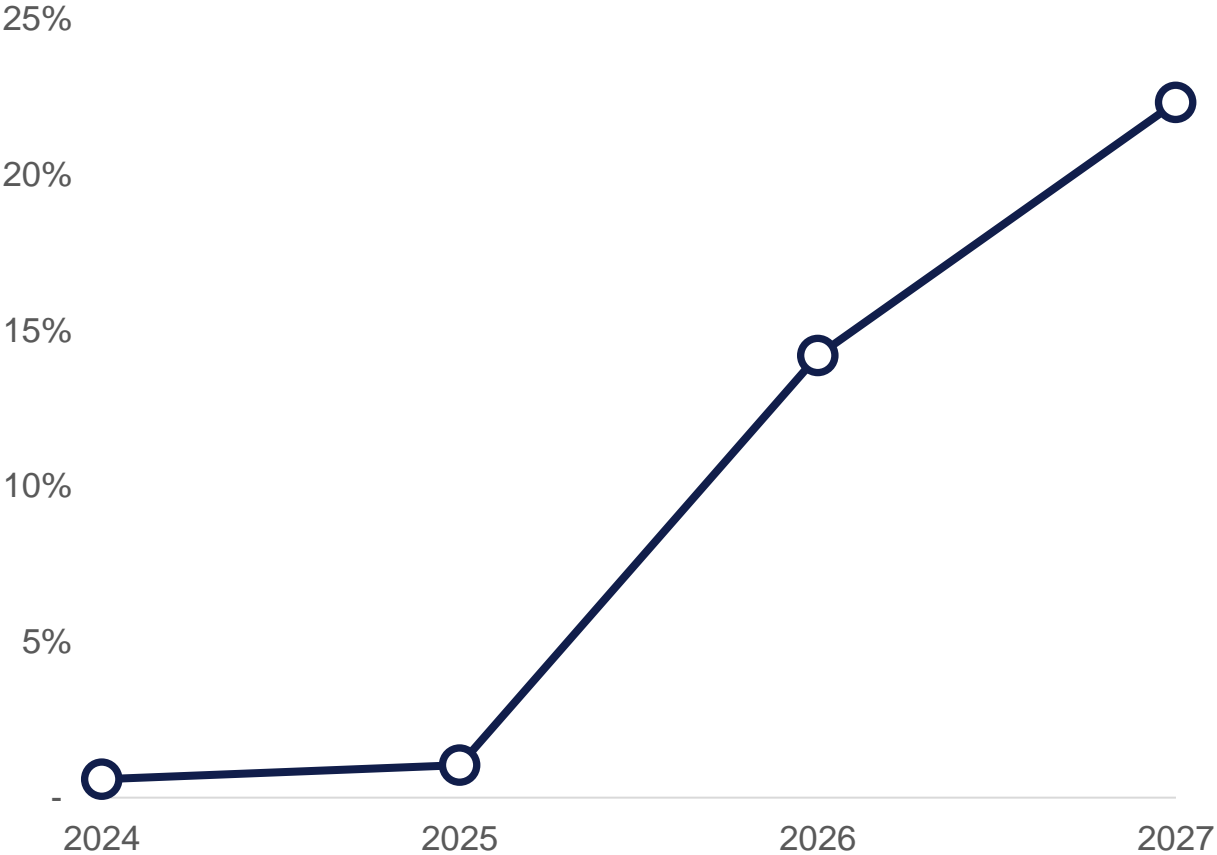
Note: These sensitivities are general estimates of anticipated impacts on our business segments & overall business of changes relative to our assumptions; the impact of actual changes may vary significantly depending on the affected asset, product & contract. See Non-GAAP Financial Measures & Reconciliations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

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

b) As of 12/31/2023, we had ~\$6.2 billion of fixed-to-floating interest rate swaps on our long-term debt.

# Cash Taxes: Do Not Expect to Be a Material Cash Taxpayer Until 2026

PROJECTED FEDERAL TAX RATE



Do not expect to be a material taxpayer under the Minimum Book Tax in 2024 or 2025

\$299 million of General Business Credits<sup>(a)</sup> that can be used to offset up to 75% of MBT annually

Expect to become an ordinary federal cash taxpayer in 2027


100% of MBT payments can be credited against future ordinary taxes

a) Total as of 12/31/2023.


# Sustainability Ratings Recognition

Highly rated by multiple agencies


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




**FTSE #2**  
of Oil & Gas  
Pipelines subsector



**MSCI AA**  
Oil & Gas Refining,  
Marketing, Transportation  
& Storage Industry



**Sustainalytics #5**  
of 117 Oil & Gas  
Storage & Transportation &  
#5 of 210 Refiners & Pipelines



**Refinitiv #7**  
of 230 Oil & Gas  
Related Equipment  
and Services Companies



**JUST Capital #4**  
of 14 Energy Equipment  
and Services



**SSGA top 10%**  
R-Factor in  
Oil & Gas – Midstream sector



Included in several sustainability indices FTSE4Good, S&P 500 ESG, JUST Capital JULCD

Note: Ratings / rankings as of January 2024.

# Joint Venture Treatment in Key Metrics

	<b>KM does not control nor consolidate</b> KM portion referred to as equity investments in financial statements	<b>KM controls &amp; fully consolidates</b> third party portion referred to as noncontrolling interests in financial statements	
<b>Example JVs</b>	SNG (50%), NGPL (37.5%), GCX (34%) Please see Note 7 in our 10K for list of material equity investments	Elba Liquefaction (25.5%), BOSTCO (55%)	
<b>Financial Metrics</b>	<p>Earnings from Equity Investments <i>KM share of JV Net Income</i></p> <hr/> <p><b>Net Income &amp; Segment EBDA</b></p> <p>+ Certain Items <i>KM share</i></p> <hr/> <p><b>Adjusted Segment EBDA</b></p> <p>+ DD&amp;A + Book Taxes <i>KM share</i></p> <hr/> <p><b>Adjusted EBITDA</b></p> <p>- Cash Taxes - Sustaining Capex <i>KM share</i></p> <hr/> <p><b>Distributable Cash Flow (DCF)</b></p>	<p>Consolidated throughout income statement <i>100% of JV</i></p> <hr/> <p><b>Net Income</b></p> <p>+ DD&amp;A + G&amp;A and Corporate Charges + Interest Expense + Book Taxes <i>100% of JV</i></p> <hr/> <p><b>Segment EBDA</b></p> <p>+ Certain Items <i>100% of JV</i></p> <hr/> <p><b>Adjusted Segment EBDA</b></p>	<p>Consolidated throughout income statement <i>100% of JV</i></p> <hr/> <p><b>Net Income</b></p> <p>- Net Income Attributable to Noncontrolling Interests <b>Net Income Attributable to Kinder Morgan, Inc.</b> + DD&amp;A + Book Taxes + Interest Expense + Certain Items <i>KM share</i></p> <hr/> <p><b>Adjusted EBITDA</b></p> <p>- Interest Expense - Cash Taxes - Sustaining Capex <i>KM share</i></p> <hr/> <p><b>Distributable Cash Flow (DCF)</b></p>
<b>Debt</b>	<b>No JV debt included</b> JV's Adjusted EBITDA contribution is <u>after subtracting</u> interest expense	<b>100% of JV debt included, if any</b> fully consolidated on balance sheet	
<b>Sustaining Capital</b>	<b>Includes KM owned % of JV sustaining capital</b>		
<b>Discretionary Capital</b>	<b>Includes KM contributions to JVs based on % owned, including for projects &amp; debt repayment</b>		

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

# Non-GAAP Financial Measures & Reconciliations

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Defined Terms

Reconciliations for the historical periods

# 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. (previously referred to as “Adjusted Earnings”)** 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. For periods from 2016 to 2018, also reflects an adjustment for preferred stock dividends. We are adopting Adjusted Net Income Attributable to Common Stock because we believe it allows for calculation of Adjusted EPS on the most comparable basis with earnings per share, the 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 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 from Joint Ventures” below).

**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” below). DCF is a significant performance measure used by us, investors and other external users of our financial statements 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 is also used by us, investors and other external users to compare the performance of companies across our industry. 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.

**Adjusted Segment EBDA** is calculated, for an individual segment, by adjusting segment earnings before DD&A, amortization of excess cost of equity investments, 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.

## Use of Non-GAAP Financial Measures (Continued)

**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. 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 from 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.

**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; 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.

**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,” and in conjunction with capital expenditures for the project, is the basis for our Project EBITDA multiple. 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.

**CO<sub>2</sub> EOR & Transport Free Cash Flow** is calculated by reducing Segment EBITDA from our CO<sub>2</sub> EOR & Transport assets by Certain Items, capital expenditures (sustaining and expansion) and acquisitions attributable to the EOR & Transport assets. Management uses CO<sub>2</sub> EOR & Transport Free Cash Flow as an additional performance measure for our CO<sub>2</sub> EOR & Transport assets. We do not provide budgeted CO<sub>2</sub> EOR & Transport Segment EBITDA (the GAAP financial measure most directly comparable to 2024 budgeted CO<sub>2</sub> 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

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

\$ in millions

	2024	2023	Change	
	Budget	Actual	\$	%
<b>Net income attributable to KMI</b>	<b>\$ 2,726</b>	<b>\$ 2,391</b>	<b>\$ 335</b>	<b>14%</b>
Certain Items				
Change in fair value of derivative contracts	-	(126)	126	100%
Loss on impairment	-	67	(67)	(100%)
Income tax Certain Items	-	33	(33)	(100%)
Other	-	45	(45)	(100%)
Total Certain Items	-	19	(19)	(100%)
<b>Adjusted Net income attributable to KMI</b>	<b>\$ 2,726</b>	<b>\$ 2,410</b>	<b>\$ 316</b>	<b>13%</b>

<b>Net income attributable to KMI</b>	<b>\$ 2,726</b>	<b>\$ 2,391</b>	<b>\$ 335</b>	<b>14%</b>
Total Certain Items	-	19	(19)	(100%)
DD&A	2,411	2,250	161	7%
Amortization of excess cost of equity investments	-	66	(66)	(100%)
Income tax expense <sup>(a)</sup>	785	682	103	15%
Cash taxes	(46)	(11)	(35)	(318%)
Sustaining capital expenditures	(990)	(868)	(122)	(14%)
Amounts from joint ventures				
Unconsolidated JV DD&A	331	323	8	2%
Remove consolidated JV partners' DD&A	(63)	(63)	-	-
Unconsolidated JV income tax expense <sup>(b)(c)</sup>	85	89	(4)	(4%)
Unconsolidated JV cash taxes <sup>(b)</sup>	(79)	(76)	(3)	(4%)
Unconsolidated JV sustaining capital expenditures	(193)	(163)	(30)	(18%)
Remove consolidated JV partners' sustaining capital expenditures	11	9	2	22%
Other items <sup>(d)</sup>	67	67	-	-
<b>DCF</b>	<b>\$ 5,045</b>	<b>\$ 4,715</b>	<b>\$ 330</b>	<b>7%</b>

Note: Adjusted Net Income Attributable to KMI 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) Associated with our Citrus, NGPL and Products (SE) Pipe Line equity investments.

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

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

# Reconciliation of Segment EBDA to Adjusted Segment EBDA

\$ in millions

	2024 Budget	2023 Actual
<b>Segment EBDA<sup>(a)</sup></b>		
Natural Gas Pipelines Segment EBDA	5,524	5,282
Certain Items <sup>(b)</sup>		
Change in fair value of derivative contracts	-	(122)
Other	-	-
<b>Certain Items</b>	-	(122)
<b>Natural Gas Pipelines Adjusted Segment EBDA</b>	<b>5,524</b>	<b>5,160</b>
Products Pipelines Segment EBDA	1,218	1,062
Certain Items <sup>(b)</sup>		
Change in fair value of derivative contracts	-	(1)
Loss on impairment	-	67
<b>Certain Items</b>	-	66
<b>Products Pipelines Adjusted Segment EBDA</b>	<b>1,218</b>	<b>1,128</b>
Terminals Segment EBDA	1,054	1,040
CO <sub>2</sub> Segment EBDA	849	689
Certain Items <sup>(b)</sup>		
Change in fair value of derivative contracts	-	4
<b>Certain Items</b>	-	4
<b>CO<sub>2</sub> Adjusted Segment EBDA</b>	<b>849</b>	<b>693</b>
<b>Total Adjusted Segment EBDA<sup>(c)</sup></b>	<b>8,645</b>	<b>8,021</b>

a) Includes revenues, earnings from equity investments, operating expenses, gain on divestitures and impairments, net, other income, 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) See "Non-GAAP Financial Measures—Certain Items."

c) 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.

# Reconciliations of KMI FCF and CO<sub>2</sub> EOR & Transport FCF

\$ in millions

Reconciliation of KMI FCF	2019	2020	2021	2022	2023
<b>CFFO (GAAP)</b>	<b>\$ 4,748</b>	<b>\$ 4,550</b>	<b>\$ 5,708</b>	<b>\$ 4,967</b>	<b>\$ 6,491</b>
Capital expenditures (GAAP) <sup>(a)</sup>	(2,270)	(1,707)	(1,281)	(1,621)	(2,317)
<b>FCF</b>	<b>2,478</b>	<b>2,843</b>	<b>4,427</b>	<b>3,346</b>	<b>4,174</b>
Dividends paid (GAAP)	(2,163)	(2,362)	(2,443)	(2,504)	(2,529)
<b>FCF after dividends</b>	<b>\$ 315</b>	<b>\$ 481</b>	<b>\$ 1,984</b>	<b>\$ 842</b>	<b>\$ 1,645</b>

## Reconciliation of CO<sub>2</sub> EOR & Transport FCF

EBDA for CO <sub>2</sub> EOR & Transport (GAAP)	\$ 681	\$ (292)	\$ 752	\$ 800	\$ 660
Certain items:					
Loss (gain) on non-cash impairments, project write-offs and divestitures	75	950	(10)	-	-
Derivatives and other	(49)	(6)	4	(11)	4
Severance tax refund	-	-	-	-	-
<b>Adjusted EBDA for CO<sub>2</sub> EOR &amp; Transport</b>	<b>707</b>	<b>652</b>	<b>746</b>	<b>789</b>	<b>664</b>
Capital expenditures (GAAP) <sup>(a)</sup>	(349)	(186)	(185)	(275)	(255)
Acquisitions	-	-	-	-	(13)
<b>CO<sub>2</sub> EOR &amp; Transport FCF</b>	<b>\$ 358</b>	<b>\$ 466</b>	<b>\$ 561</b>	<b>\$ 514</b>	<b>\$ 396</b>

a) Includes sustaining and expansion capital expenditures.

# Reconciliation of Adjusted EBITDA, Normalized for Divestitures

\$ in millions

Reconciliation of Adjusted EBITDA, Normalized for Divestitures	2016	2017	2018	2019	2020	2021	2022	2023
<b>Net income attributable to KMI</b>	<b>\$ 708</b>	<b>\$ 183</b>	<b>\$ 1,609</b>	<b>\$ 2,190</b>	<b>\$ 119</b>	<b>\$ 1,784</b>	<b>\$ 2,548</b>	<b>\$ 2,391</b>
NCI associated with Certain Items	(8)	-	-	-	-	-	-	-
KML noncontrolling interests <sup>(a)</sup>	-	28	58	33	-	-	-	-
<b>Certain Items</b>								
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)
Loss on impairment	848	170	317	(280)	1,927	1,535	-	67
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
Noncontrolling interests	-	-	240	(4)	-	-	-	-
Other	(20)	21	(20)	(37)	72	16	32	45
<b>Total Certain Items</b>	<b>933</b>	<b>1,445</b>	<b>501</b>	<b>(29)</b>	<b>1,892</b>	<b>1,220</b>	<b>88</b>	<b>19</b>
DD&A	2,209	2,261	2,297	2,411	2,164	2,135	2,186	2,250
Amortization of excess cost of equity investments	59	61	95	83	140	78	75	66
Income tax expense <sup>(a)</sup>	899	853	645	627	588	860	747	682
Interest, net <sup>(a)</sup>	1,999	1,871	1,891	1,816	1,610	1,518	1,524	1,804
<b>Amounts from joint ventures</b>								
Unconsolidated JV DD&A	362	398	412	411	407	312	323	323
Remove consolidated JV partners' DD&A	(13)	(16)	(22)	(19)	(40)	(44)	(50)	(63)
Unconsolidated JV income tax expense <sup>(a)</sup>	94	114	82	95	82	83	75	89
<b>Adjusted EBITDA</b>	<b>\$ 7,242</b>	<b>\$ 7,198</b>	<b>\$ 7,568</b>	<b>\$ 7,618</b>	<b>\$ 6,962</b>	<b>\$ 7,946</b>	<b>\$ 7,516</b>	<b>\$ 7,561</b>
Divested adjusted EBITDA <sup>(a)</sup>	(714)	(548)	(539)	(411)	(100)	(64)	(60)	(18)
<b>As normalized for divestitures</b>	<b>\$ 6,528</b>	<b>\$ 6,650</b>	<b>\$ 7,029</b>	<b>\$ 7,207</b>	<b>\$ 6,862</b>	<b>\$ 7,882</b>	<b>\$ 7,456</b>	<b>\$ 7,543</b>

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

# Reconciliation of Net Debt

\$ in millions

<b>Reconciliation of Net Debt</b>	2016	2017	2018	2019	2020	2021	2022	2023	2024B
Current portion of debt	\$ 2,696	\$ 2,828	\$ 3,388	\$ 2,377	\$ 2,558	\$ 2,646	\$ 3,385	\$ 4,049	\$ 1,749
Total long-term debt	37,354	35,015	33,936	31,915	32,131	30,674	28,403	28,067	30,081
Debt fair value adjustments	(1,149)	(927)	(731)	(1,032)	(1,293)	(902)	(115)	(187)	-
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)	-
Less: cash & cash equivalents	(684)	(264)	(3,280)	(185)	(1,184)	(1,140)	(745)	(83)	-
<b>Net Debt</b>	<b>\$ 38,160</b>	<b>\$ 36,409</b>	<b>\$ 33,137</b>	<b>\$ 33,031</b>	<b>\$ 32,042</b>	<b>\$ 31,214</b>	<b>\$ 30,936</b>	<b>\$ 31,837</b>	<b>\$ 31,830</b>
Adjusted EBITDA	\$ 7,242	\$ 7,198	\$ 7,568	\$ 7,618	\$ 6,962	\$ 7,946	\$ 7,516	\$ 7,561	\$ 8,156
<b>Net Debt to Adjusted EBITDA</b>	<b>5.3X</b>	<b>5.1X</b>	<b>4.4X</b>	<b>4.3X</b>	<b>4.6X</b>	<b>3.9X</b>	<b>4.1X</b>	<b>4.2X</b>	<b>3.9X</b>

# Reconciliation of Adjusted Net Income Attributable to KMI and Adjusted EBITDA Excluding Uri

\$ in millions

	2021 Actual	2021 Actual Excluding Uri
<b>Reconciliation of Adjusted Net income attributable to KMI and Adjusted EBITDA Excluding Uri</b>		
<b>Net income attributable to KMI</b>	<b>\$ 1,784</b>	<b>\$ 932</b>
Certain Items		
Fair value amortization	(19)	(19)
Legal, environmental and other reserves	160	160
Change in fair value of derivative contracts	19	19
Loss on impairment	1,535	1,535
Income tax Certain Items	(491)	(491)
Other	16	16
Total Certain Items	1,220	1,220
<b>Adjusted Net Income attributable to KMI</b>	<b>3,004</b>	<b>2,152</b>
<b>Net income attributable to KMI</b>	<b>\$ 1,784</b>	<b>\$ 932</b>
Total Certain Items	1,220	1,220
DD&A	2,135	2,135
Amortization of excess cost of equity investments	78	78
Income tax expense <sup>(a)</sup>	860	620
Interest, net <sup>(a)</sup>	1,518	1,518
Amounts from joint ventures		-
Unconsolidated JV DD&A	312	312
Remove consolidated JV partners' DD&A	(44)	(44)
Unconsolidated JV income tax expense <sup>(a)</sup>	83	83
<b>Adjusted EBITDA</b>	<b>\$ 7,946</b>	<b>\$ 6,854</b>

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

# Computation of the Refined Products Contributions to the Products Pipelines Adjusted Segment EBDA

\$ in millions

<b>Computation of the Refined Products Contributions to the Products Pipelines Adjusted Segment EBDA</b>	2015	2016	2017	2018	2019	2020	2021	2022	2023
<b>Products Pipelines Segment EBDA (GAAP)</b>	<b>\$ 1,106</b>	<b>\$ 1,067</b>	<b>\$ 1,231</b>	<b>\$ 1,209</b>	<b>\$ 1,225</b>	<b>\$ 977</b>	<b>\$ 1,064</b>	<b>\$ 1,107</b>	<b>\$ 1,062</b>
Certain Items	(35)	107	(67)	(20)	30	50	53	-	66
<b>Products Pipelines Adjusted Segment EBDA</b>	<b>1,071</b>	<b>1,174</b>	<b>1,164</b>	<b>1,189</b>	<b>1,255</b>	<b>1,027</b>	<b>1,117</b>	<b>1,107</b>	<b>1,128</b>
Less: Crude & Condensate Contributions to Adjusted Segment EBDA	381	464	441	446	484	366	359	331	332
<b>Refined Products Contributions to the Products Pipelines Adjusted Segment EBDA</b>	<b>\$ 690</b>	<b>\$ 710</b>	<b>\$ 723</b>	<b>\$ 743</b>	<b>\$ 771</b>	<b>\$ 661</b>	<b>\$ 758</b>	<b>\$ 776</b>	<b>\$ 796</b>