KINDER MORGAN

2020 Investor Day

January 29, 2020

Disclosure

Forward looking statements / non-GAAP financial measures

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Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. These statements are necessarily based upon various assumptions involving judgments with respect to the future, including, among others, the timing and extent of changes in the supply of and demand for the products we transport and handle; national, international, regional and local economic, competitive, political and regulatory conditions and developments; the timing and success of business development efforts; the timing, cost, and success of expansion projects; technological developments; condition of capital and credit markets; inflation rates; interest rates; the political and economic stability of oil-producing nations; energy markets; federal, state or local income tax legislation; weather conditions; environmental conditions; business, regulatory and legal decisions; terrorism; cyber-attacks; and other uncertainties. Important factors that could cause actual results to differ materially from those expressed in or implied by forward-looking statements. These factors include the risks and uncertainties described in this presentation and in our most recent Annual Report on Form 10-K and subsequently filed Exchange Act reports filed with the SEC (including under the headings "Risk Factors," "Information Regarding Forward-Looking Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere). These reports are available through the SEC's EDGAR system at www.sec.gov and on our website at www.kindermorgan.com.

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

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

Kinder Morgan 2020 Investor Day

Agenda and presenters

TIME	DISCUSSION	PRESENTER	
8:00 – 8:20	Our Vision	**Rich Kinder** *Executive Chairman*	
8:20 – 9:00	Strategy	**Steve Kean** *CEO*	
9:00 – 9:40	Business Review	**Kim Dang** *President*	
9:40 – 9:50	**BREAK**		
9:50 – 10:35	Panel with Business Unit Presidents	**Tom Martin,** *President of Natural Gas* **James Holland,** *President of Products* **John Schlosser,** *President of Terminals* **Jesse Arenivas,** *President of CO_2*	
10:35 – 11:00	2020 Budget	**David Michels** *VP & CFO*	
11:00 – 11:30	Q&A		

Our Vision

Delivering energy to improve lives
& create a better world

Rich Kinder

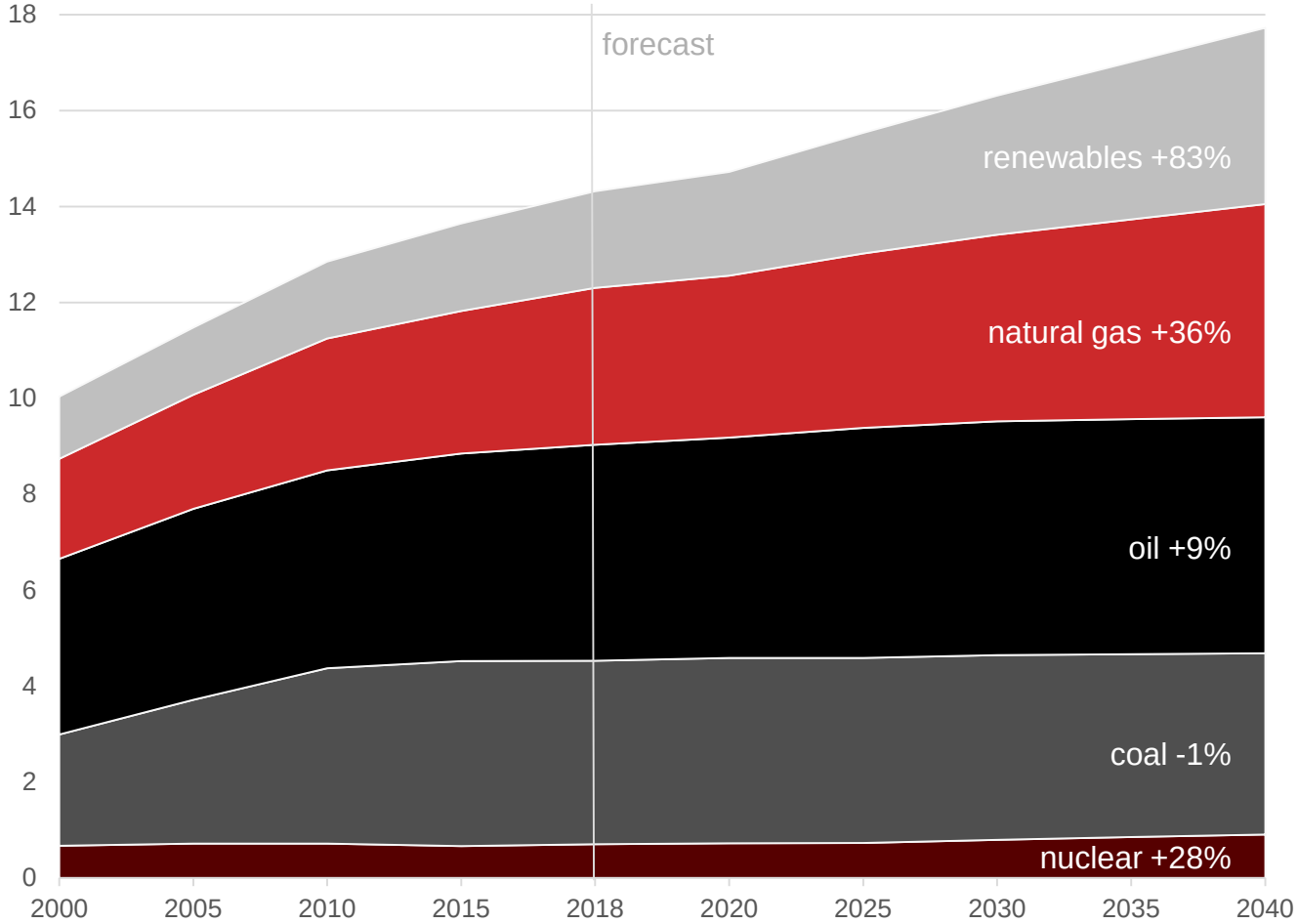
Executive Chairman

Hydrocarbons Required to Meet Long-Term Global Demand

U.S. energy infrastructure will be critical for decades

GLOBAL PRIMARY ENERGY DEMAND BY FUEL

billion tons oil equivalent



Broad-based natural gas demand growth across all sectors leads to growing share of total energy demand

- Led by global industrial development (industrial demand growth is >2x power generation growth through 2030)
- Asia Pacific region accounts for ~50% of the demand growth over the next two decades

Oil demand increases through 2030, though growth rate slows in late 2020s

- Long-distance freight, shipping, aviation & petrochemical demand continue growing
- Passenger car fuel demand projected to peak in late 2020s due to fuel efficiency, electric vehicles & compressed natural gas

Continued growth expected from U.S. shale

- U.S. provides 85% of increase in global oil production & 30% of increase in global natural gas production by 2030
- By 2025, U.S. shale alone overtakes Russia in total oil & gas production

Source: International Energy Agency, World Energy Outlook, November 2019 (Stated Policies Scenario)
Note: Growth figures relative to 2018 (latest actual). World primary energy demand includes final energy consumption by end-use sectors, fuel use in power generation (electricity & heat plants) & other energy sector (includes transformation industries such as coal mines & oil & gas extraction, as well as losses converting primary energy into form used by end-sectors).

World is Expected to Grow by Nearly 1 Billion People by 2030

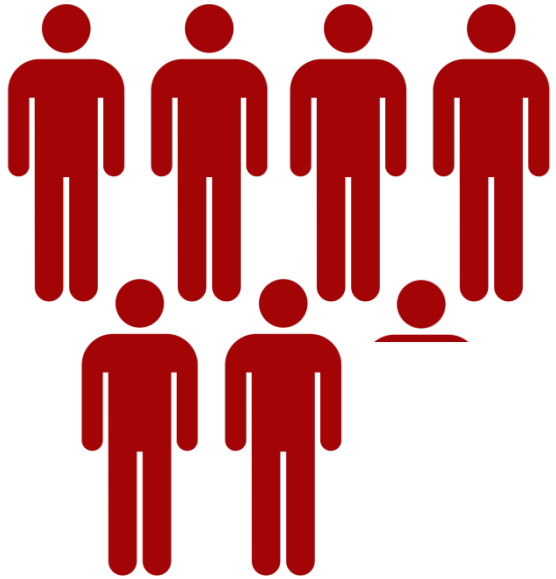
Over 90% of population growth occurs in developing economies

2018 billions of people

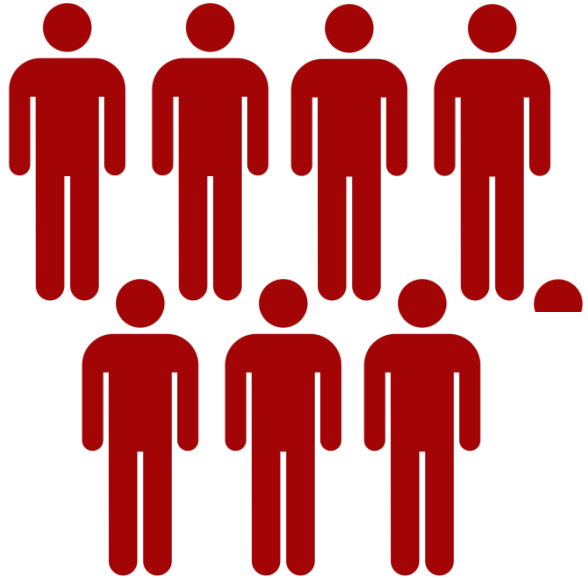
2030 billions of people

Non-OECD: ~6.3 BILLION

Over 80% of people
live in developing economies
such as India, China, Sub-Saharan Africa,
Indonesia, Pakistan, Brazil, etc.

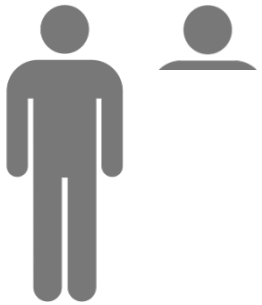


Over 850
million more people

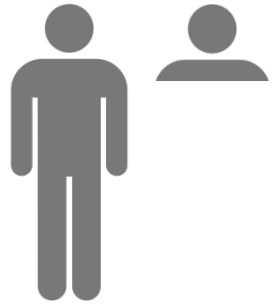


OECD: ~1.3 BILLION

Less than 20% of people
live in advanced economies
such as U.S., Japan, European Union,
South Korea, Canada, Australia, etc.



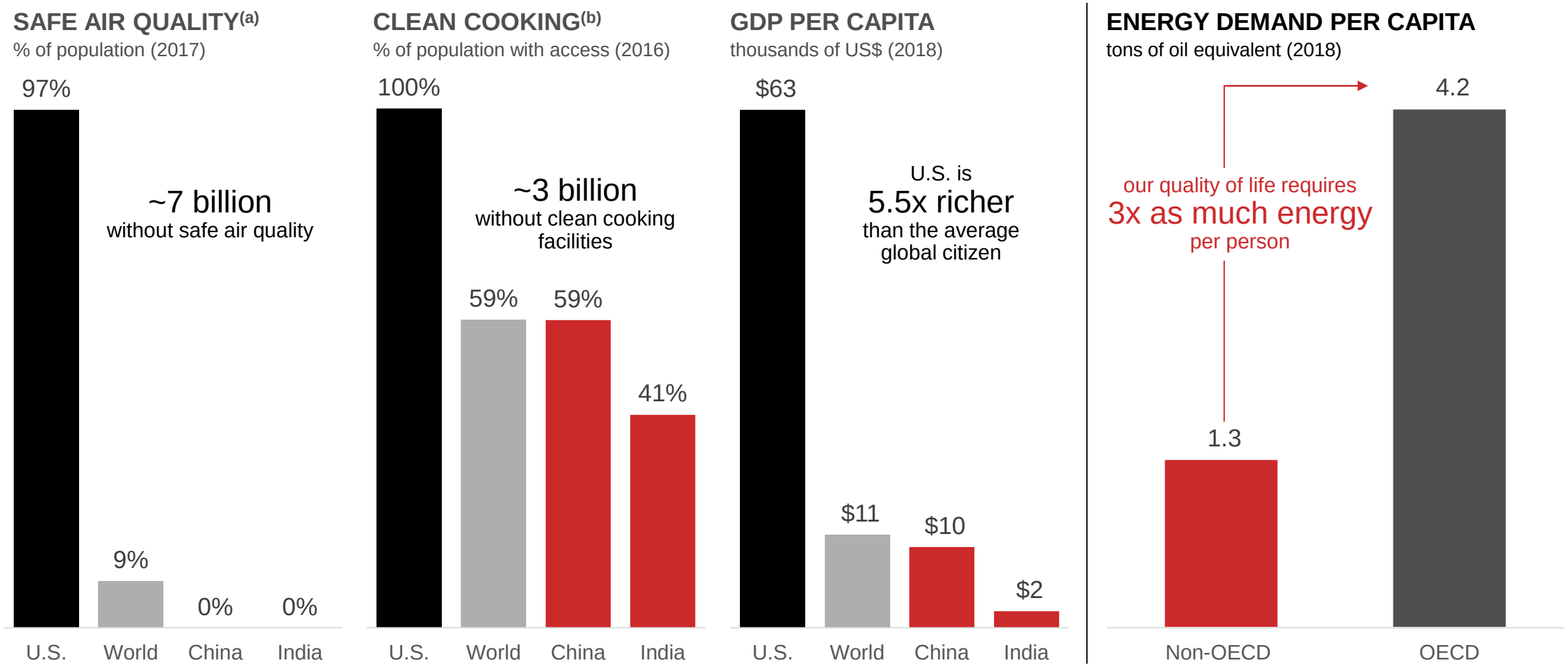
Around 50
million more people



Source: International Energy Agency, World Energy Outlook, November 2019 (Stated Policies Scenario)
Note: Organization for Economic Co-operation & Development (OECD) includes 36 member countries which represent ~80% of world trade & investment.

Many People Still Lack Basic Needs & Technologies

Developing countries, led by Asia, are the main engines of global growth



Source: World Bank, International Telecommunication Union, World Health Organization, International Energy Agency, World Energy Outlook, November 2019 (Stated Policies Scenario)

a) Per the World Health Organization's air quality guideline value of 10 micrograms per m^3 for ambient concentrations of particulate matter smaller than 2.5 µm ($PM_{2.5}$). These are the lowest levels at which total, cardiopulmonary & lung cancer mortality have been shown to increase with over 95% confidence in response to long term exposure to $PM_{2.5}$. In some areas, combustion of wood & other biomass fuels can be an important source.

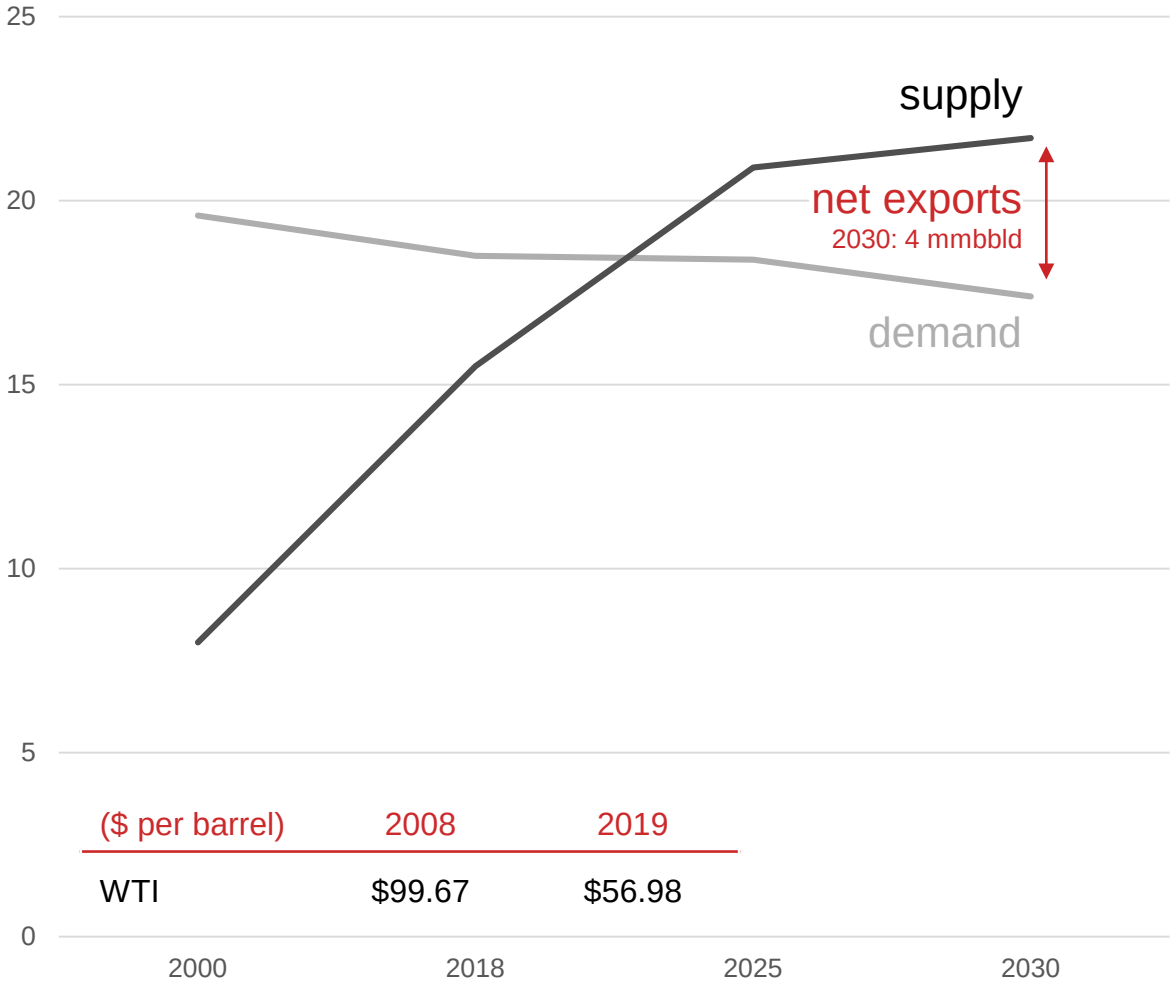
b) Percent primarily using clean cooking fuels & technologies. The use of solid fuels & kerosene in households is associated with increased mortality from pneumonia & other acute lower respiratory diseases among children, as well as increased mortality from chronic obstructive pulmonary disease, cerebrovascular & ischemic heart diseases & lung cancer among adults.

U.S. Expected to Produce More Energy than it Needs

Surplus of affordable energy to meet demand abroad

U.S. OIL & LIQUIDS

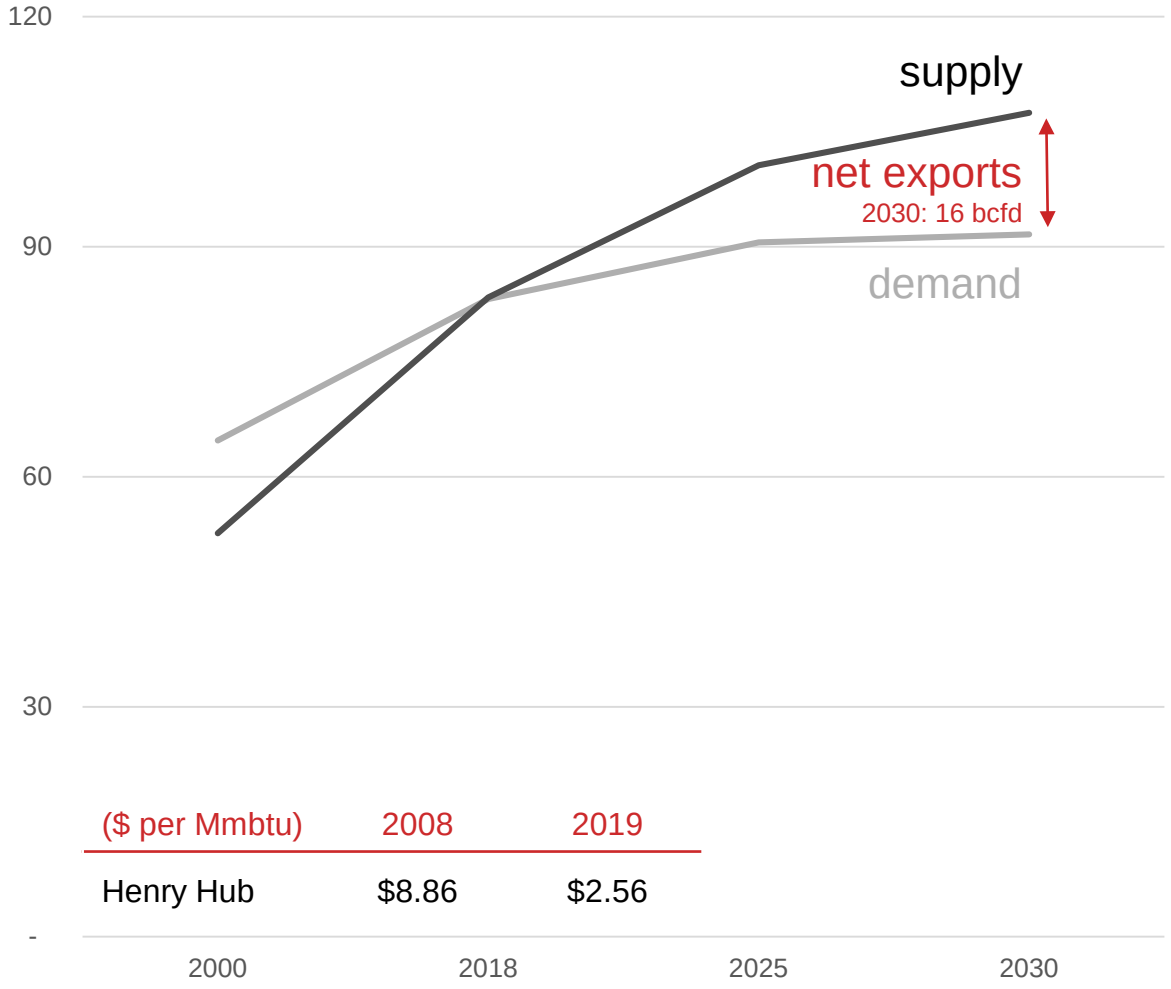
million barrels per day



($ per barrel)	2008	2019
WTI	$99.67	$56.98

U.S. NATURAL GAS

billion cubic feet per day



($ per Mmbtu)	2008	2019
Henry Hub	$8.86	$2.56

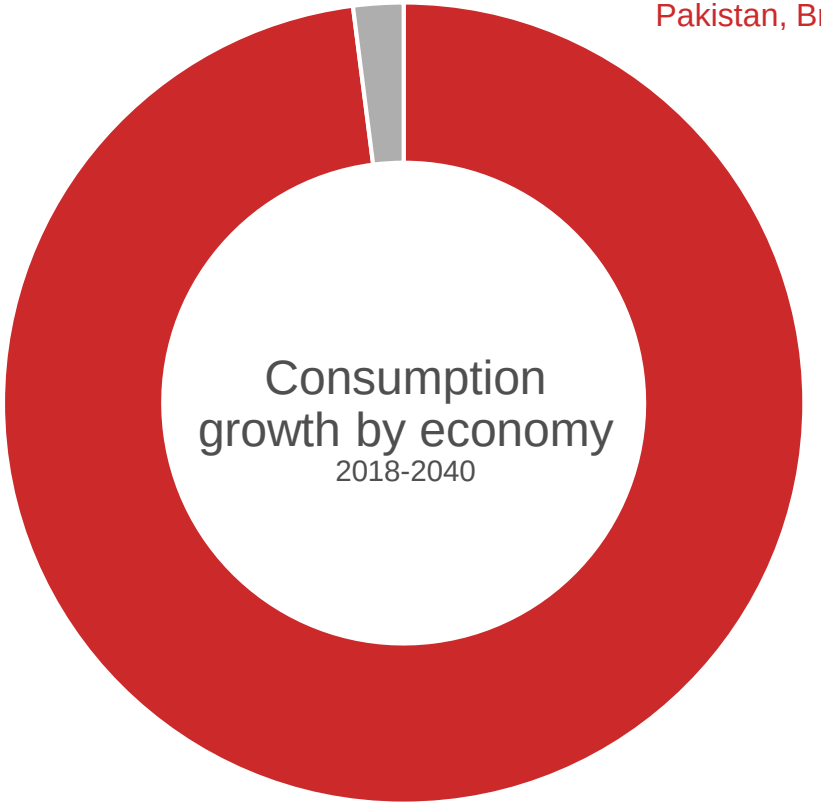
Source: International Energy Agency, World Energy Outlook, November 2019 (Stated Policies Scenario), U.S. Energy Information Administration (commodity prices)
Note: Oil production includes lease condensate & natural gas liquids. Oil demand includes petroleum liquids.

Developing Economies Drive Energy Demand Growth

Energy consumption much more than just power & electric vehicles

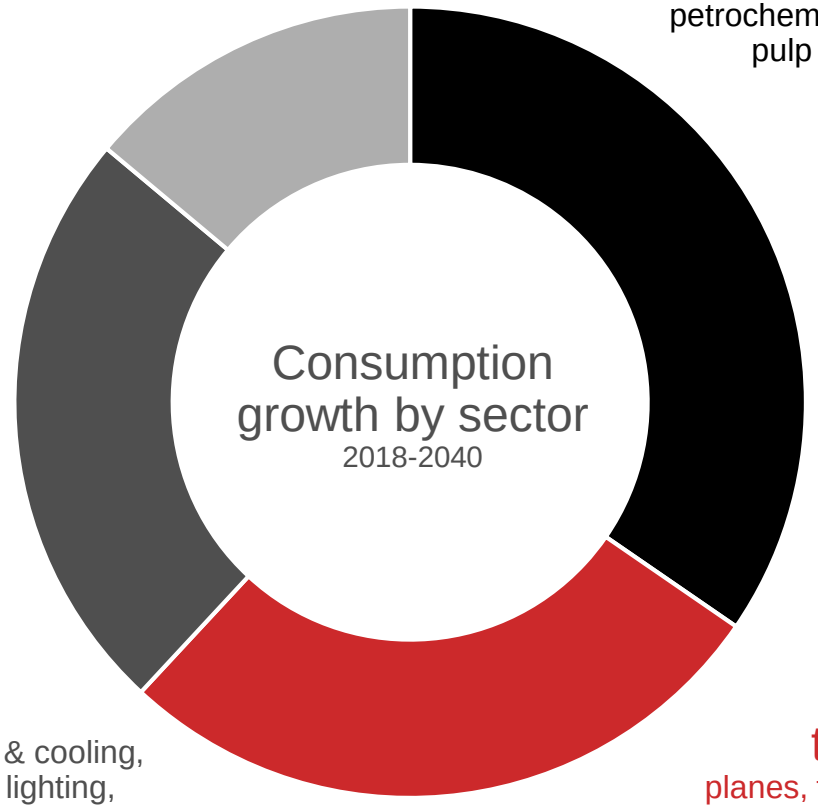
rest of world
only 2% of expected growth

non-OECD
such as India, China, Sub-Saharan Africa, Indonesia, Pakistan, Brazil, etc.



other
agricultural, asphalt, lubricants & other

industry
manufacturing & construction, including iron, steel, chemical / petrochemical, cement, pulp & paper, etc.



buildings
space heating & cooling, water heating, lighting, appliances, electronics & cooking equipment

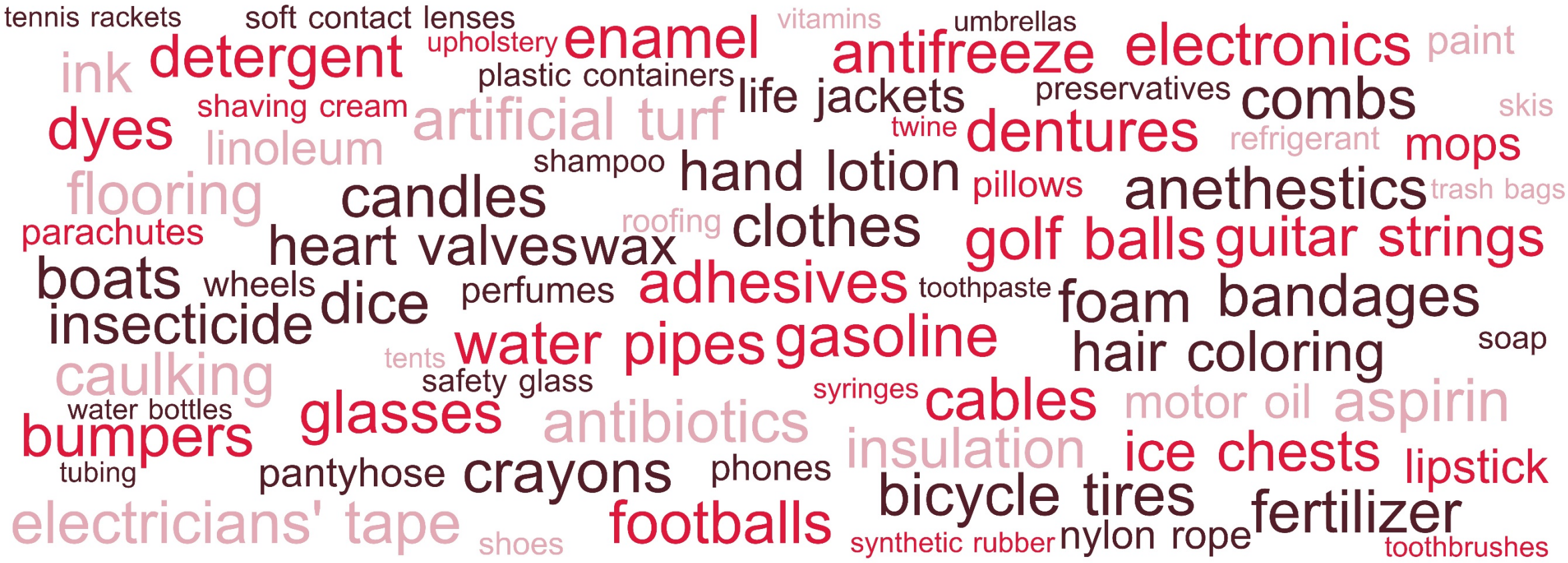
transport
planes, trains, boats, trucks & automobiles for personal & freight movement

Source: International Energy Agency, World Energy Outlook, November 2019, (Stated Policies Scenario)
Note: Final energy consumption is energy demand by the various end-use sectors shown on right side. Power / electricity is included & comprises ~20% of end-use consumption. % of growth measured in billion tons of oil equivalent.

Hydrocarbons Are Essential to Our Quality of Life

Fueling our modern materials & conveniences

Natural gas & petroleum heat our homes & water, generate much of our electricity & are inputs to products we use every day:



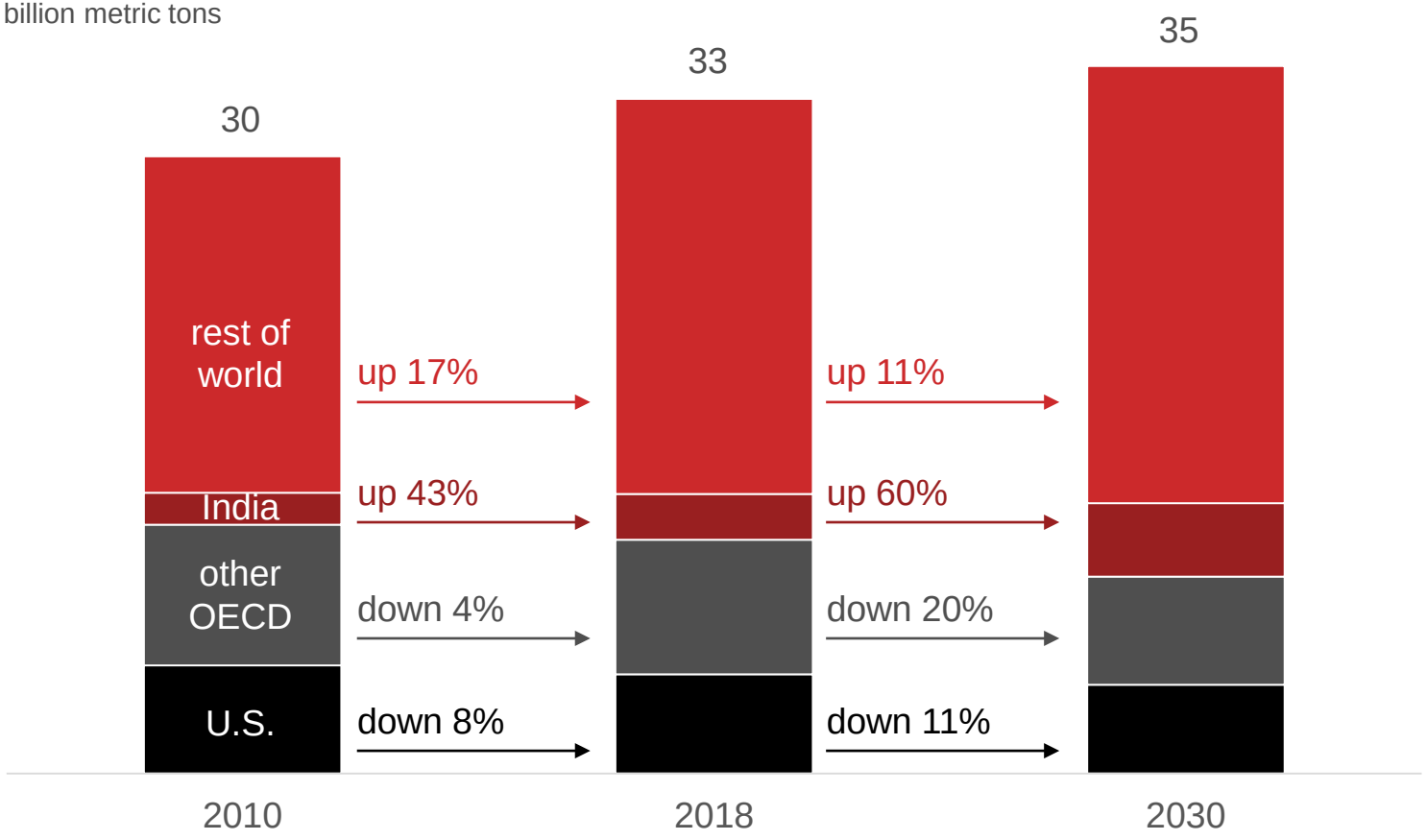
Note: Text size not indicative of relative demand.

Significant Environmental Concern in Developing Economies

Ambient air pollution accounts for an estimated 4.2 million deaths per year

ENERGY-RELATED CO_2 EMISSIONS

billion metric tons



Developing economy emissions expected to more than offset reductions achieved by U.S., the E.U. & elsewhere over next 10 years

DELHI, INDIA

26 million people | Air quality statistic: 143 $PM_{2.5}$

HOUSTON, TEXAS

6 million people | Air quality statistic: 10 $PM_{2.5}$

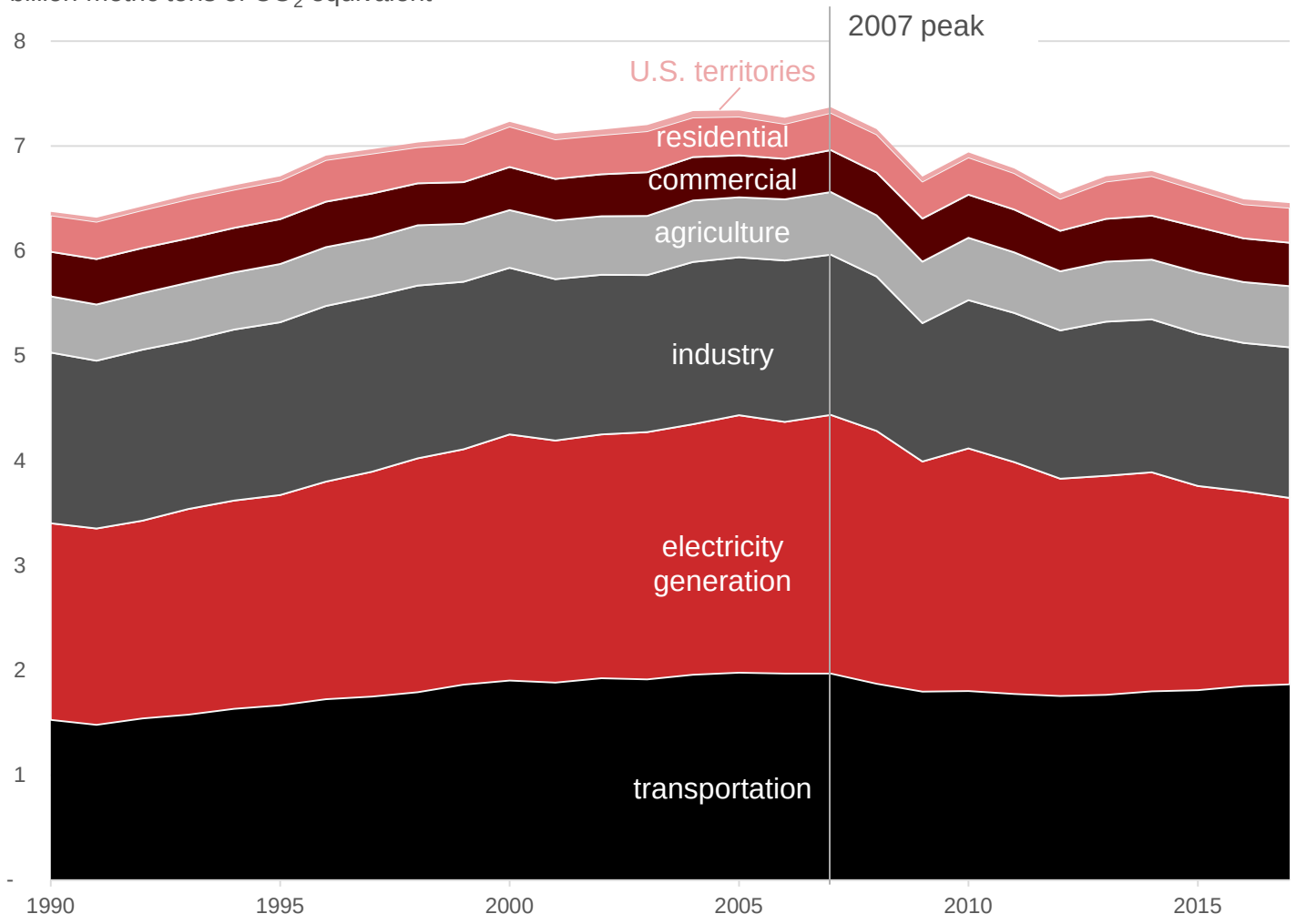
Source: International Energy Agency, World Energy Outlook, November 2019 (Stated Policies Scenario), World Health Organization (population, air quality statistics), Washington Post (New Delhi), Photographylife.com (Houston)
Note: WHO air quality guideline is 10 $PM_{2.5}$ (particulate matter with diameter <2.5 micrometers). Delhi statistics measured in 2016. Houston statistics measured in 2014 & includes surrounding areas of Sugar Land & Baytown.

U.S. Greenhouse Gas Emissions are Declining

Meaningful progress led by natural gas replacing coal-fired power generation

U.S. GREENHOUSE GAS EMISSIONS BY ECONOMIC SECTOR

billion metric tons of CO_2 equivalent



Source: U.S. EPA Inventory of U.S. Greenhouse Gas Emissions & Sinks 1990-2017 (released in 2019), U.S. Energy Information Administration, World Bank
Note: Statistics relative to 2017, which is the latest year available for emissions data. GDP increase using current US$.

Since 1990:

- Total U.S. emissions are about flat
  - despite 16% increase in energy consumed
  - with over 200% increase in GDP
  - and 30% population growth
- Electricity-related emissions are down 5%
  - despite 34% increase in power generated
- Methane emissions are down 16%
  - while natural gas production is up over 50%

Since 2007 peak:

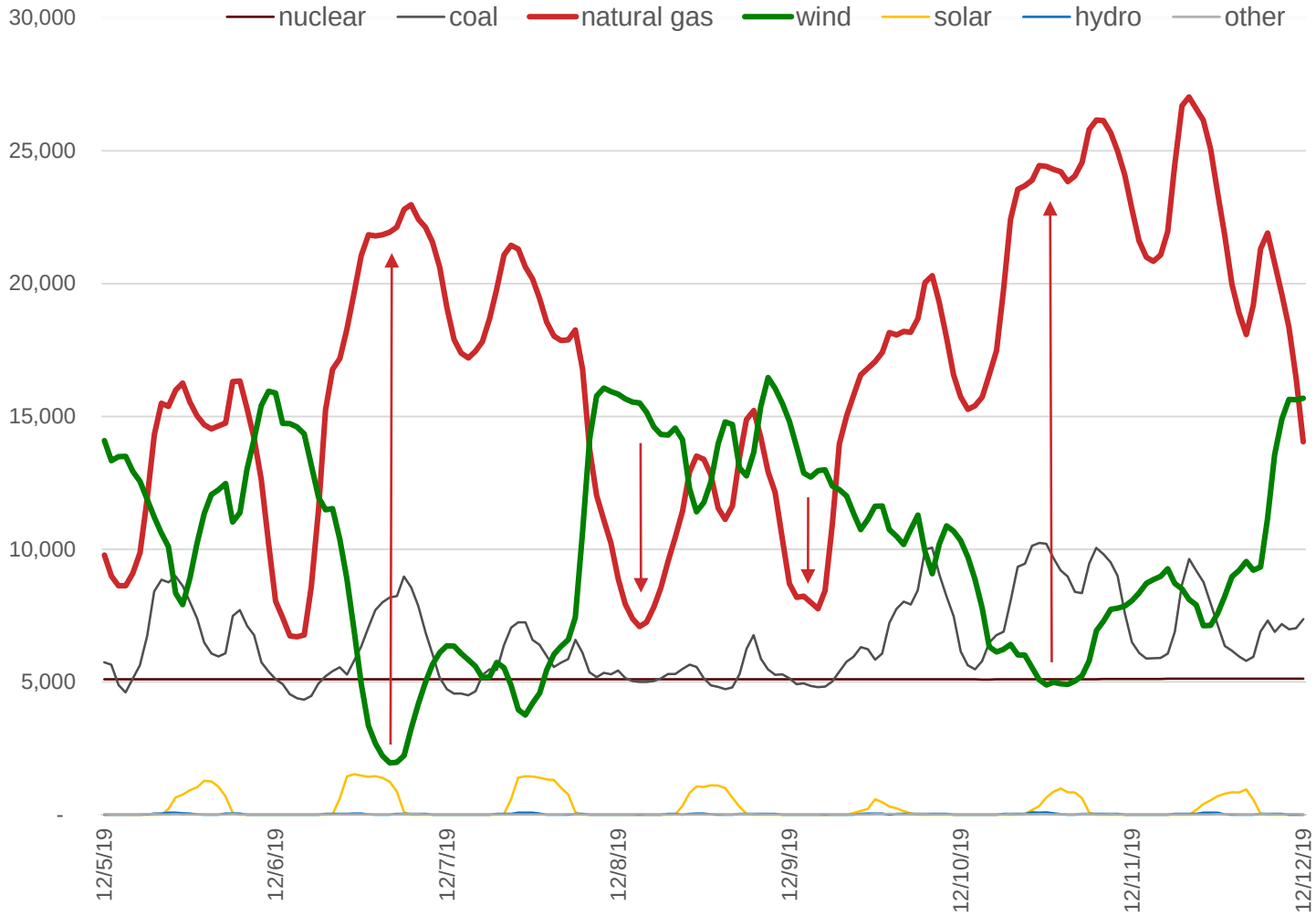
- Total U.S. emissions are down 12%
- Electricity-related emissions are down 28%

U.S. GHG emissions have declined to below 1993 levels

Natural Gas is a Critical Partner to Renewable Energy

Evidence shows natural gas is preferred backup for renewables

7 DAYS OF ELECTRICITY GENERATION IN TEXAS (megawatt-hours by source)



- Natural gas works hand-in-hand with renewables like wind & solar
  - Provides energy supplies when renewable sources are intermittent
  - Can be dispatched quickly
  - Incredibly energy-dense & efficient
  - Results in new deliverability requirements for existing infrastructure
- Natural gas provides affordable solution for reducing energy emissions
  - Low-cost, abundant & cleaner-burning
  - Significant infrastructure in place
  - Without a reliable backup, renewables would require excess capacity, resulting in meaningful upfront Scope 3 emissions[(a)]

Greater natural gas capacity is required to complement growing renewables

Source: U.S. EIA Hourly Electric Grid Monitor

a) National Renewable Energy Laboratory estimates ~60-70% of solar photovoltaics (PV) & ~86% of wind life cycle GHG emissions are in upstream processes, such as raw materials extraction, module manufacturing & construction. These emissions would be included in Scope 3 emissions. Natural gas plant emissions are primarily from operational processes, such as power generation, plant operation & maintenance, included in Scope 1 & 2 emissions.

Conclusions

Developing economies will drive energy demand growth

(population growth & satisfaction of basic needs)

U.S. excess supply will serve global demand growth

U.S. greenhouse gas emissions are declining

Long runway for hydrocarbon use, especially natural gas

Strategy

Steve Kean

CEO

Kinder Morgan: Leader in North American Energy Infrastructure

Unparalleled & irreplaceable asset footprint built over decades

Largest natural gas transmission network

- ~70,000 miles of natural gas pipelines
- 659 bcf of working storage capacity
- Connected to every important U.S. natural gas resource play & key demand centers
- Move ~40% of U.S. natural gas consumption & exports
- ~1,200 miles of natural gas liquids pipelines

Largest independent transporter of refined products

- Transport ~1.7 mmbbld of refined products
- ~6,800 miles of refined products pipelines
- ~3,100 miles of crude pipelines

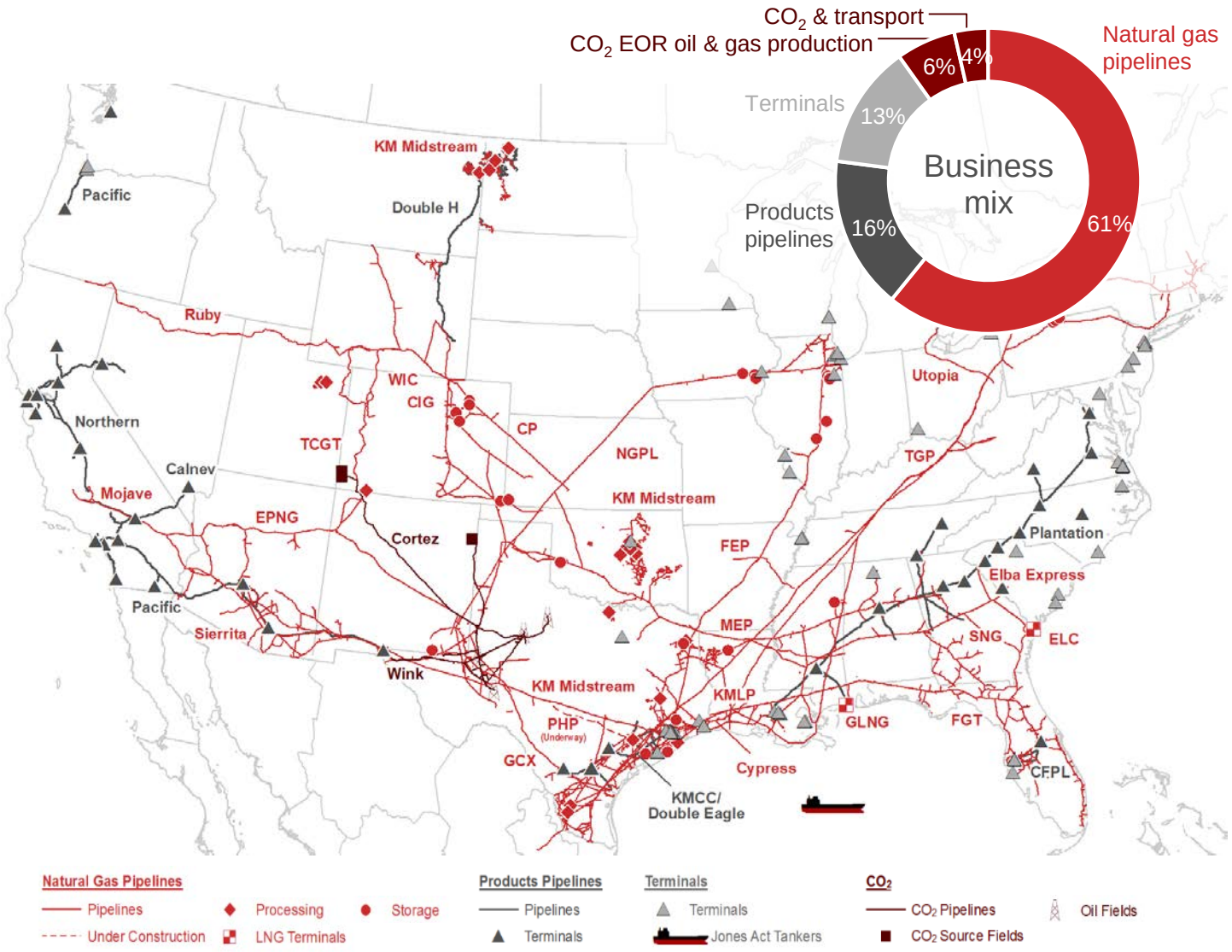
Largest independent terminal operator

- 147 terminals
- 16 Jones Act vessels

Largest transporter of CO_2

- Transport ~1.2 bcfd of CO_2

Leading infrastructure provider across multiple critical energy products



Note: Mileage & volumes are company-wide per 2020 budget. Business mix based on 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

A Core Energy Infrastructure Holding

Generating significant cash flow & returning significant value to shareholders

>$40 billion market capitalization	One of the 10 largest energy companies in the S&P 500
15% owned by management	Highly aligned management with significant equity interest
~5% current dividend yield	Based on $1.00 per share & $21.50 share price
25% dividend growth in 2020	Planned increase to $1.25 per share
$2 billion share buyback program	Purchased $525 million since December 2017

Key Milestones Reached

in 2019

Sold KML & U.S. Cochin pipeline for ~$2.5 billion

Created ~$1.2 billion balance sheet flexibility by beating leverage target

Placed major projects in service – GCX & Elba[(a)]

Demonstrated capital discipline by eliminating 1/3 of budgeted CO_2 segment investments with updated returns below our threshold

Self-funded discretionary capital primarily with operating cash flow since Q1 2016

Increased dividend 25% year-over-year

Reported methane emissions intensity for our natural gas transmission & storage of 0.02% vs. 0.31% target under ONE Future program, 7 years ahead of schedule

a) As of 1/29/2020, four of ten units are in service, representing 88% of the project's expected revenue (KM-share).

Our Strategy

Stable, fee-based assets	Financial flexibility	Disciplined capital allocation	Enhancing shareholder value
▪ Core energy infrastructure ▪ Safe & efficient operator ▪ Multi-year contracts ▪ >90% take-or-pay & fee-based cash flows	▪ 4.3x 2020B Net Debt / Adjusted EBITDA[(a)] ▪ Low cost of capital ▪ Mid-BBB credit ratings ▪ Ample liquidity	▪ Conservative assumptions ▪ High return thresholds ▪ Self-funding at least equity portion with cash flow ▪ Ongoing evaluation of best alternative for free cash flow use	▪ Attractive projects ▪ Dividend growth ▪ Share repurchases ▪ Maintain strong balance sheet

Maximize the value of our assets on behalf of shareholders

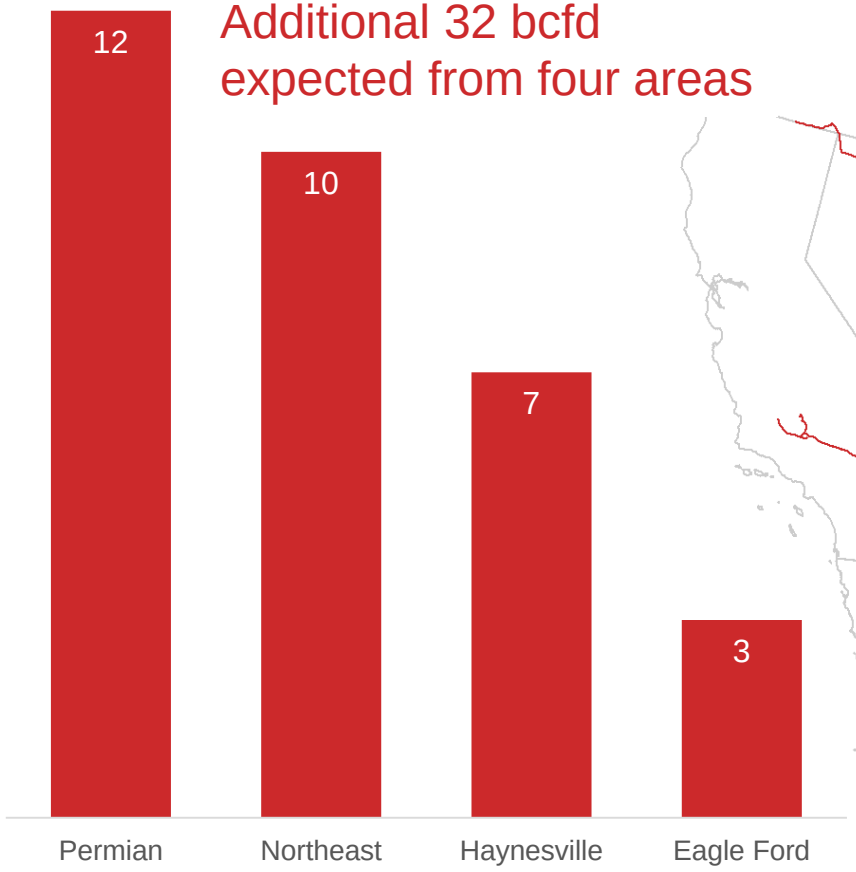
a) See Non-GAAP Financial Measures & Reconciliations.

Substantial Growth Projected for U.S. Natural Gas Supply

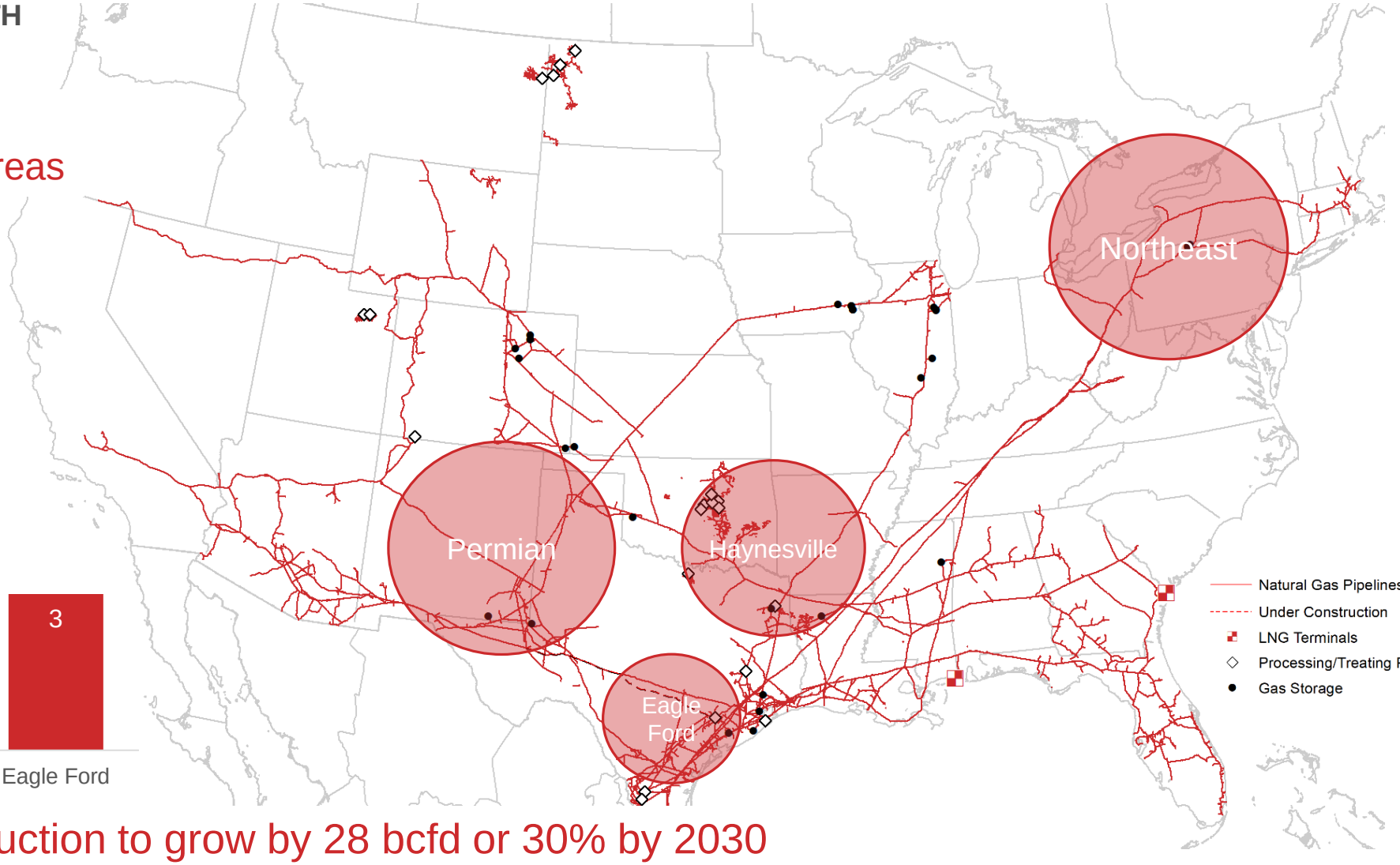
Our network connects key supply basins to multiple demand points along the Gulf Coast

KEY BASINS DRIVING U.S. GROWTH

2019 to 2030 growth in bcfd



Additional 32 bcfd expected from four areas



Total U.S. natural gas production to grow by 28 bcfd or 30% by 2030

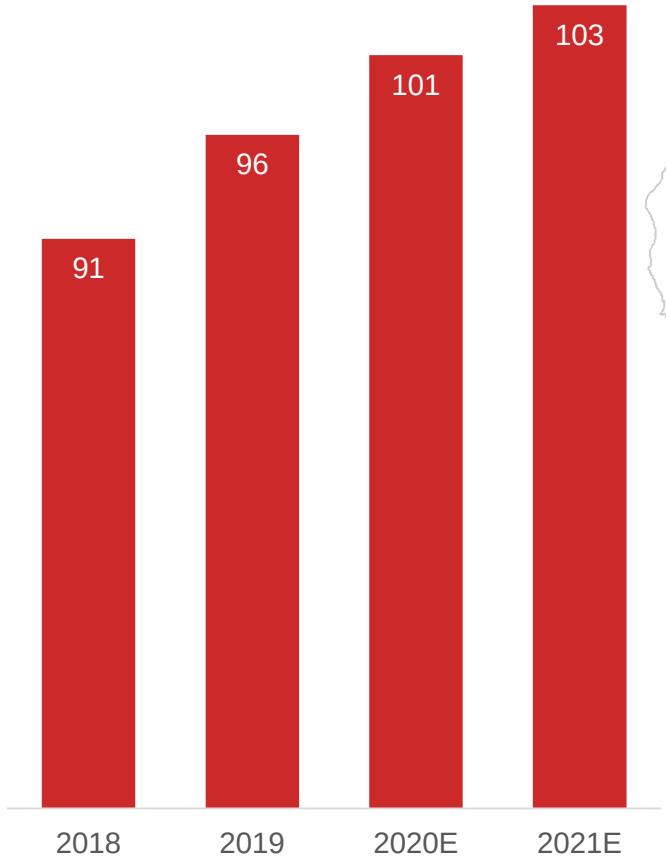
Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2019. Growth relative to projected 2019 production at the time of the report. Forecast assumes aggregate of other U.S. basins shrinks by 4 bcfd.

Our Unmatched Natural Gas Network & Deliverability

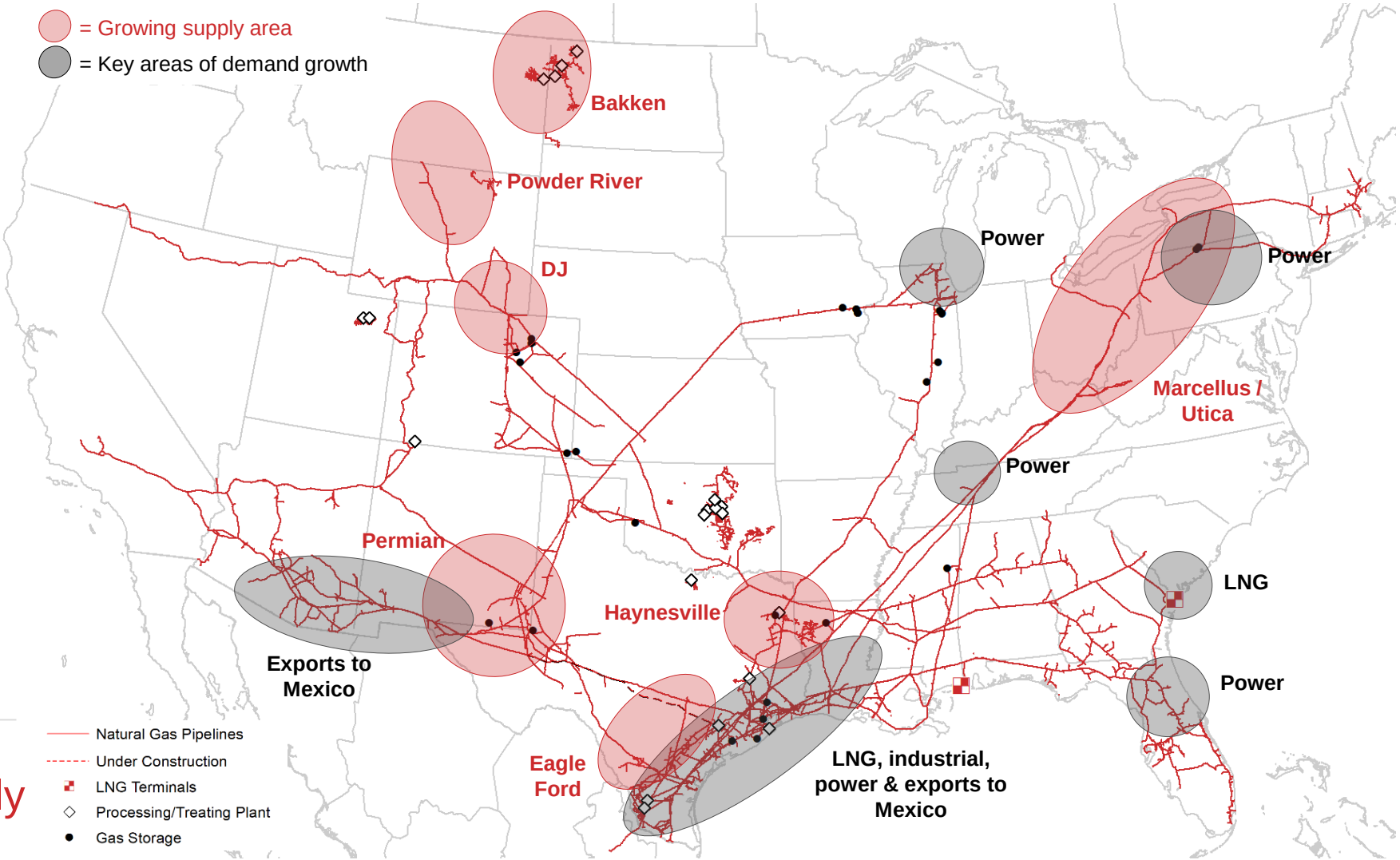
Strong fundamentals drive value on existing assets & create investment opportunities

U.S. NATURAL GAS DEMAND

bcfd



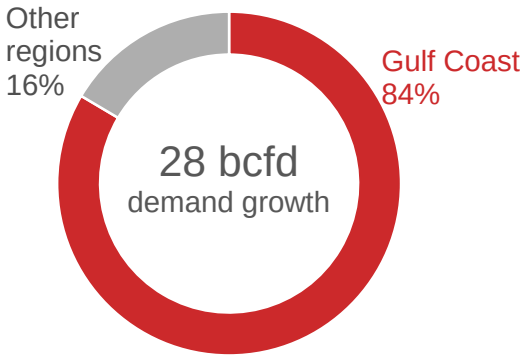
Connecting growing supply with key demand centers



Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2019.

U.S. Natural Gas Demand is Concentrated in Gulf Coast

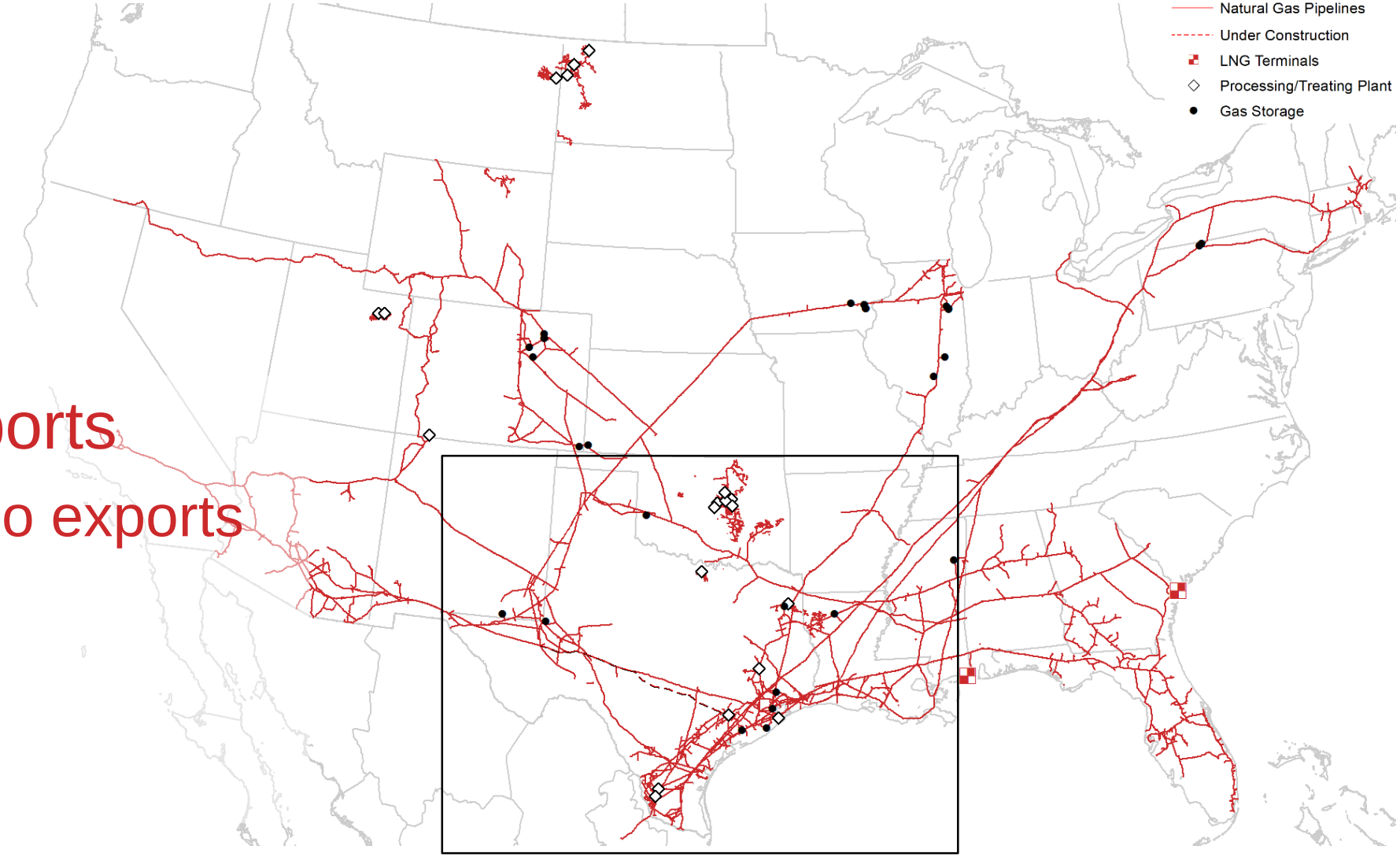
84% of forecasted 2019 – 2030 growth is in the Gulf Coast, where we have significant assets in place



GULF COAST DEMAND GROWTH

bcfd, 2019 – 2030

+15.9	LNG exports
+2.7	Net Mexico exports
+2.4	Industrial
+0.5	Power
+0.4	Transport
+1.5	Other



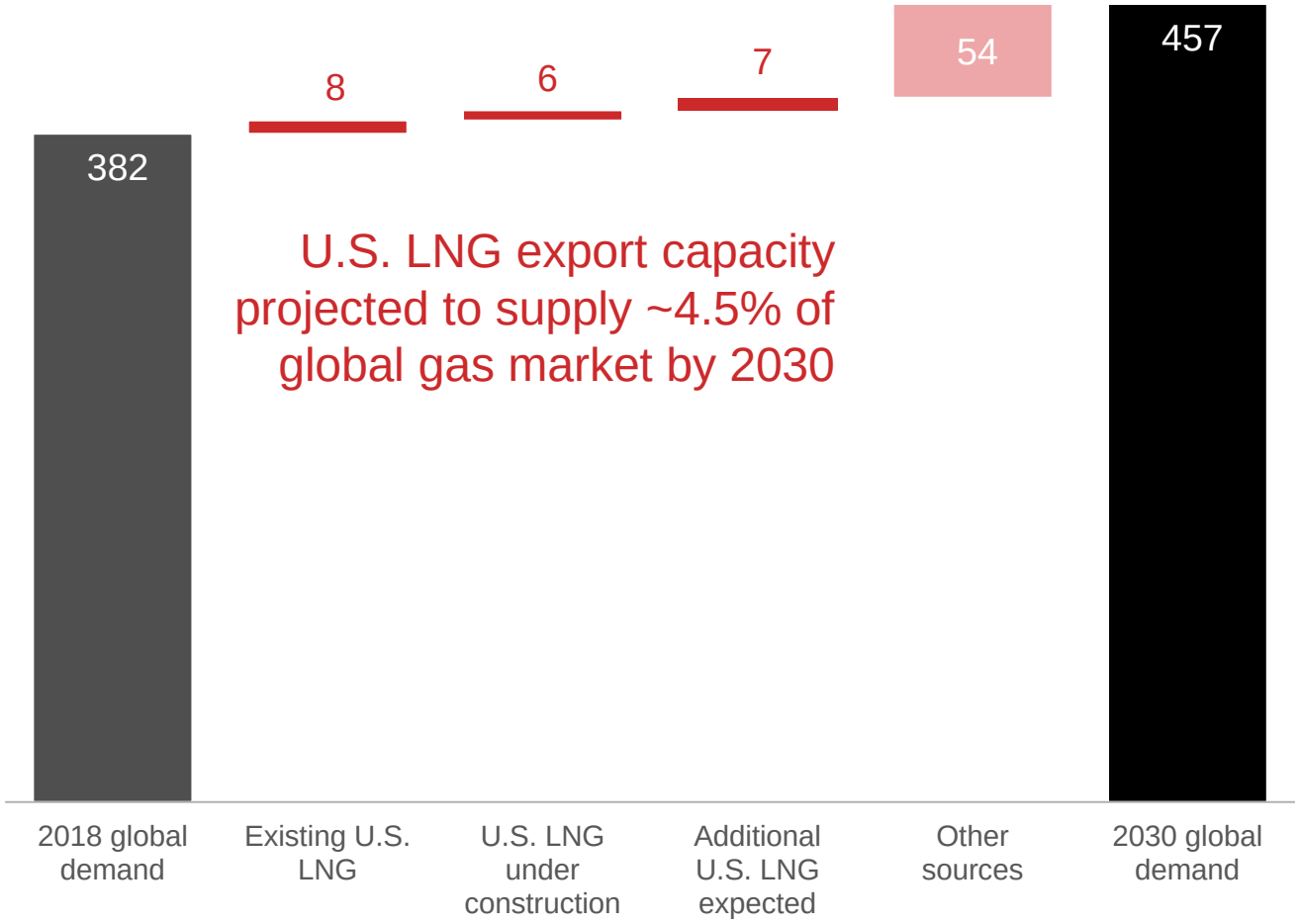
Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2019. Gulf Coast is defined by WoodMackenzie as West South Central region, which includes Texas, Louisiana, Arkansas & Oklahoma.

U.S. LNG Exports are Growing

Expected to more than triple by 2025

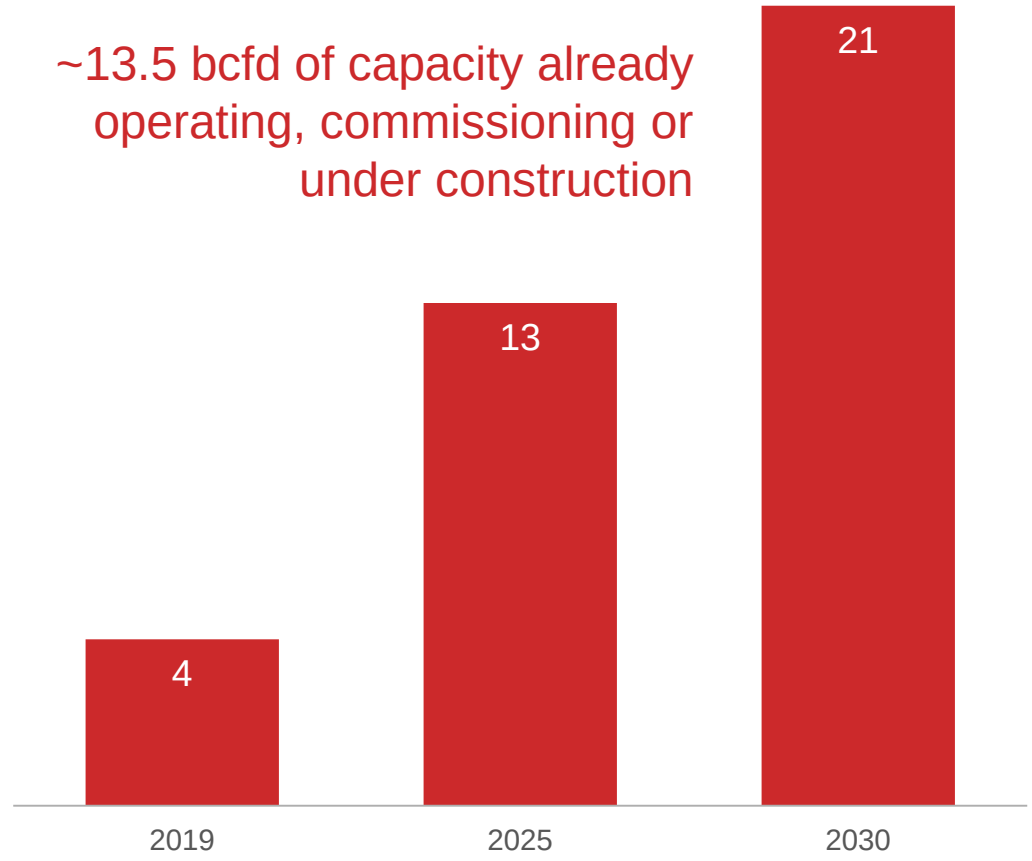
GLOBAL NATURAL GAS DEMAND

bcfd



PROJECTED U.S. LNG EXPORTS

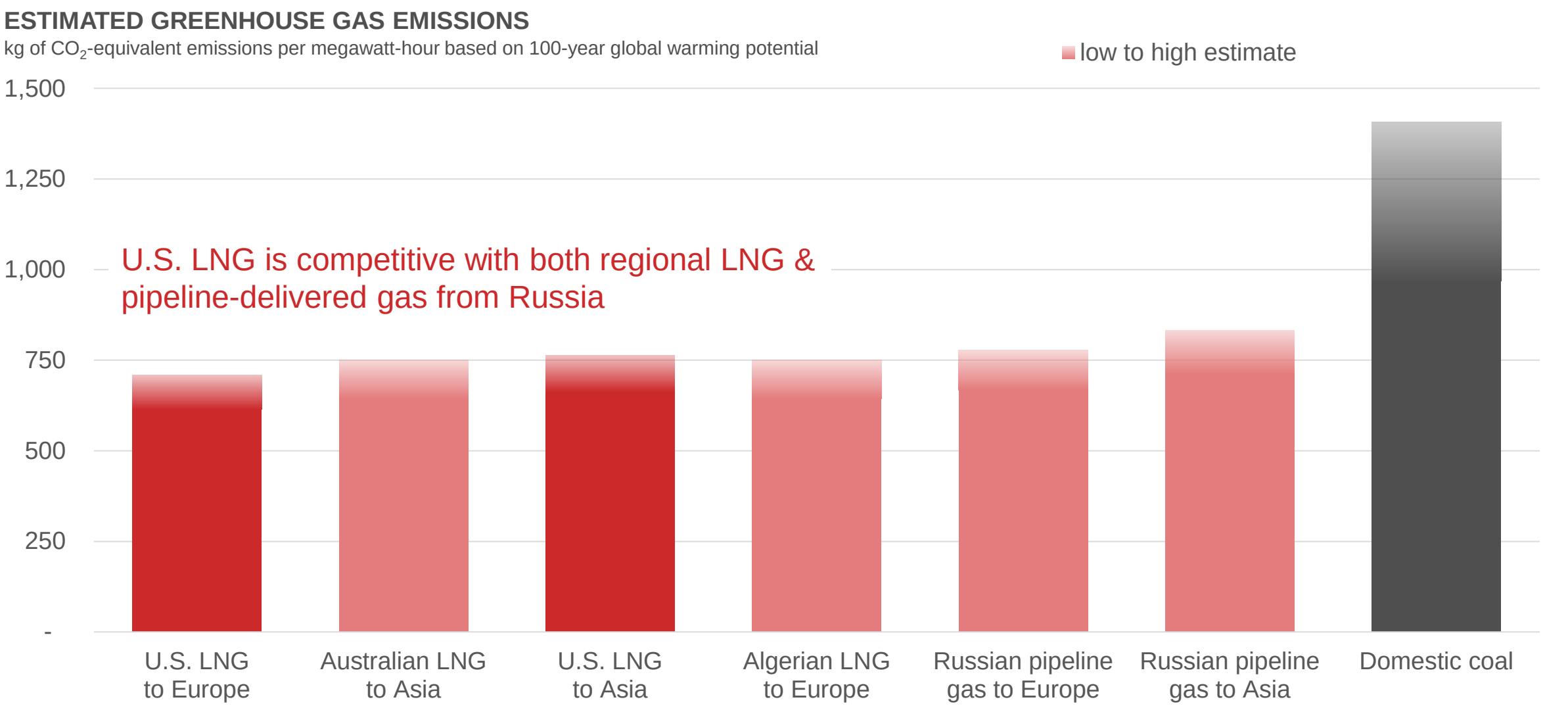
bcfd



Source: International Energy Agency, World Energy Outlook 2019 (global natural gas demand, declines at existing liquefaction facilities), U.S. EIA (U.S. liquefaction capacity), WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2019 (projected U.S. LNG exports)

Full Cycle Emissions in Electric Power Generation

U.S. LNG is one of the lowest emissions fuels for electricity in Asia & Europe



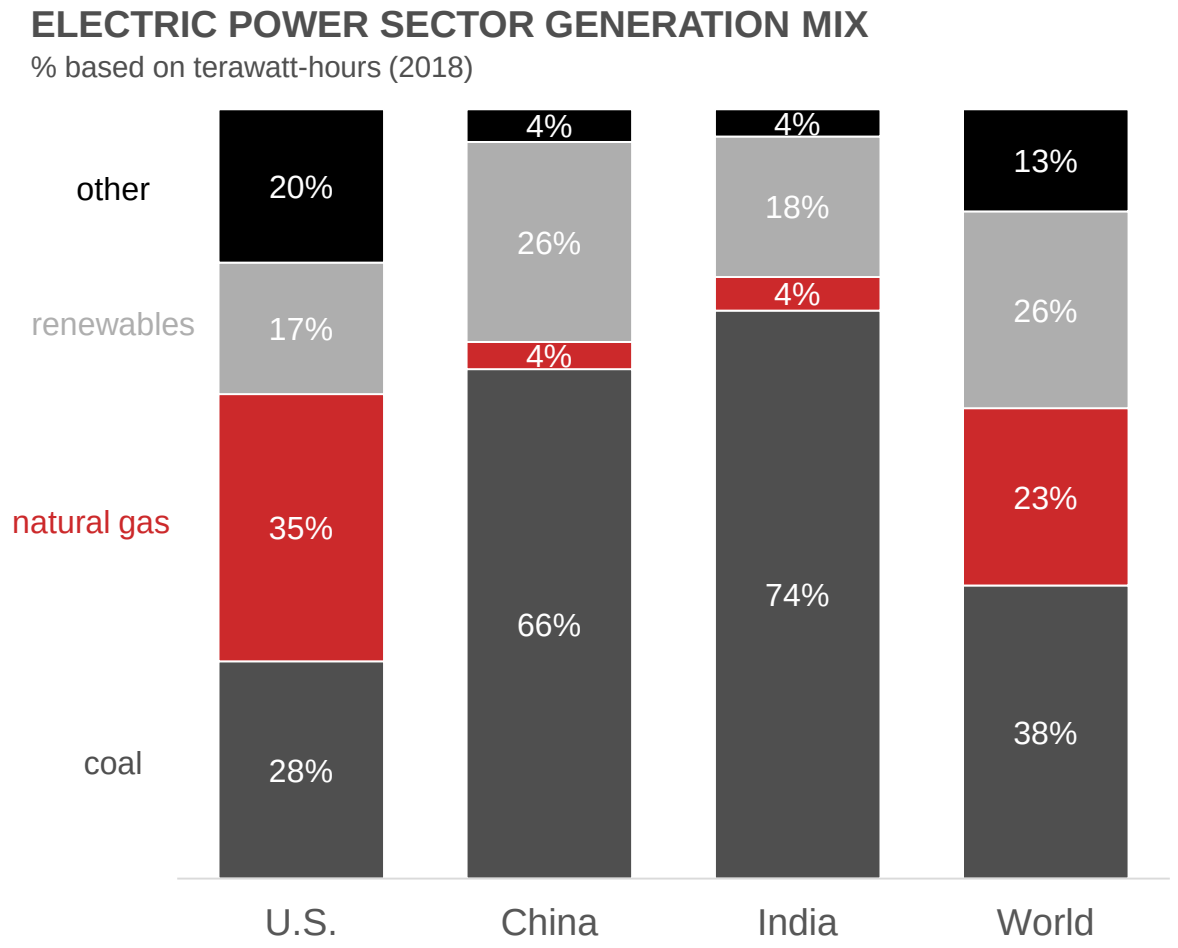
Source: U.S. National Energy Technology Laboratory, Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States: 2019 Update
Note: Several simplifying assumptions were used for the above emissions ranges, including that U.S. operations are representative of foreign operations. Please refer to the publication for a full explanation of inputs & assumptions.

Replacing Coal is Critical to Global Emission Reductions

Power sector contributes ~40% of energy-related CO_2 emissions globally

Natural gas is a more efficient & lower carbon fuel for power generation

- Burning natural gas is 25% more efficient than coal on average
- Coal releases ~75% to 85% more CO_2 per Btu than natural gas
- In combination, this means natural gas fired generation emits ~60% less than coal-fired plants
- U.S. GHG emissions have declined to early 1990s levels despite 30% population growth & >200% increase in GDP primarily due to coal-to-gas switching
- U.S. is responsible for ~15% of global emissions & declining
- Planned retirements of U.S. coal-fired plants expected to be more than offset by coal-fired plants under construction globally



"Coal-to-gas switching can provide quick wins for global emissions reductions." – IEA

Source: U.S. Energy Information Agency, U.S. National Energy Technology Laboratory, International Energy Agency, World Energy Outlook, November 2019 (Stated Policies Scenario)
Note: Efficiency statistic based on heat rate (million Btu per kWh). Other in electric power generation mix includes nuclear & oil.

$3.6bn of Commercially-Secured Capital Projects Underway

~$1.3 billion added in 2019

(as of 12/31/2019)	Demand Pull / Supply Push	KMI Capital ($ billion)	Estimated In-Service Date	Capacity
Natural Gas				
Permian takeaway projects (PHP, TX Intrastates, EPNG, NGPL)		$ 0.9	2020 – Q1 2021	4.4 bcfd
Supply for U.S. power & LDC demand (TGP, FGT, EPNG, NGPL)		0.4	2020 – 2022	0.6 bcfd
Supply for LNG export (NGPL, KMLP)		0.3	2020 – 2022	1.6 bcfd
Elba liquefaction (remaining units)		0.2	H1 2020	0.2 bcfd
Bakken G&P expansions (Hiland Williston Basin)		0.2	2020	Various
Mexico export (EPNG, Sierrita)		0.2	2020	0.6 bcfd
Other natural gas		0.2	2020 – H1 2021	>0.7 bcfd
Total Natural Gas		**$ 2.4**	**~67% of total & 5.5x EBITDA multiple**	
Additional projects		**1.2**		
Total Backlog		**$ 3.6**		

- Significant investment opportunities resulting from our expansive, strategically-located natural gas pipelines network
- Additional projects are primarily liquids-related (crude oil & refined products)
  - $0.5 billion for CO_2 oil & gas production, $0.3 billion for CO_2 & transport, $0.2 billion for Terminals & $0.2 billion for Products

Note: See Non-GAAP Financial Measures & Reconciliations. EBITDA multiple reflects KM share of estimated capital divided by estimated Project EBITDA. Rows may not sum due to rounding.

Leading the Way Out of the Permian

Successfully completed GCX on time & budget | PHP well underway

Leveraging existing footprint into new takeaway capacity that reaches across Texas & the Desert/Southwest (DSW), connecting into major demand markets

- Our advantaged network offers broad end-market optionality with deliverability to Houston markets (power, petrochemical), substantial LNG export capacity & Mexico

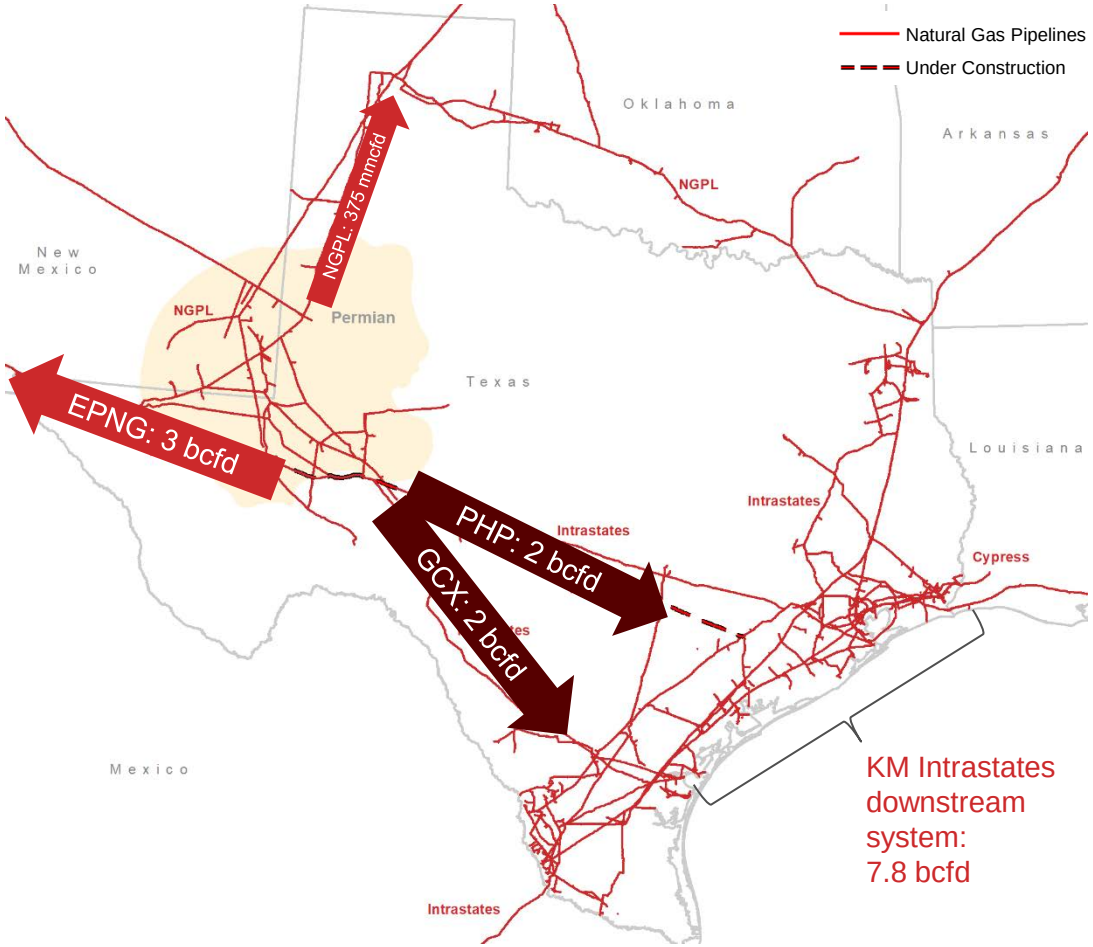
Investing more than $325 million to increase capacity & improve connectivity across existing Texas Intrastates pipeline networks by 1.7 bcfd

- Key to unlocking millions of barrels of additional oil production from the Permian Basin & billions of dollars of value
- Enhances deliverability of E. Texas natural gas supply into Houston area markets

In customer discussions about a third KMI pipeline (Permian Pass Pipeline)

- Targeting E. Texas intrastate markets & LNG terminals in E. Texas & Louisiana
- In-service date beyond 2022

	Gulf Coast Express (GCX)	Permian Highway Pipeline (PHP)
Mainline:	450 miles of 42” pipeline	~430 miles of 42” pipeline
Endpoint:	Near Agua Dulce	Near Katy
KM ownership:	34%	26.7%
Capacity:	2.0 bcfd	2.1 bcfd
Capital (100%):	$1.75 billion	$2.15 billion
In-Service:	Operating since Sept. 2019	Early 2021
Min. contract term:	10 years	10 years



Providing unparalleled takeaway capacity from the Permian basin to the Gulf Coast & DSW markets

Supporting the Buildout of U.S. LNG Exports

Serving significant liquefaction capacity & well-positioned to capture more

Kinder Morgan network advantages:

Natural gas transportation leader

~70,000 miles of natural gas pipelines
Move ~40% of U.S. natural gas consumption & exports

Supply diversity

Connected to every important U.S. natural gas resource play

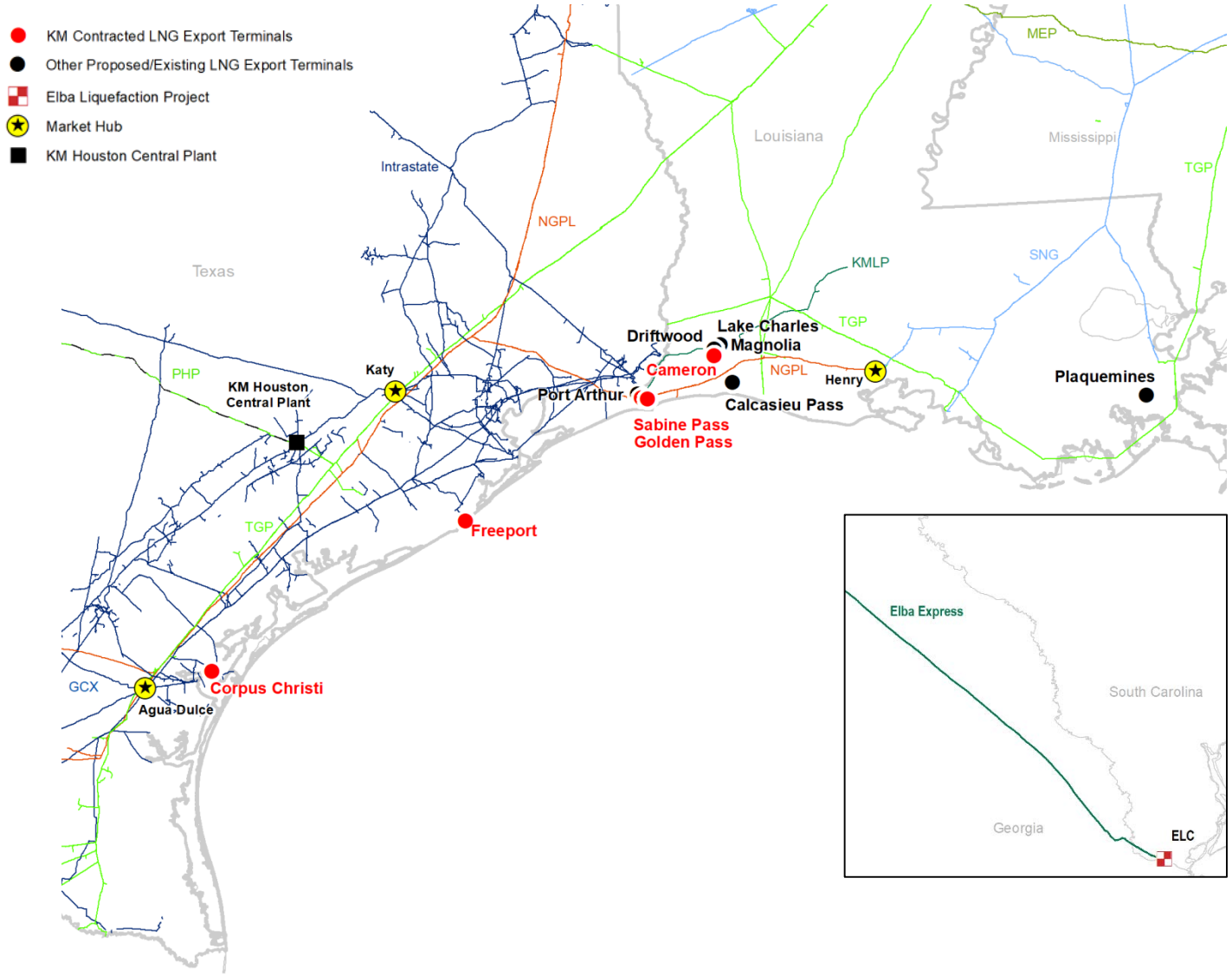
Premier deliverability

659 bcf of working gas storage in production & market areas

Transporter of choice

Contracted capacity online	Contracted capacity FID / to come	Average remaining contract term	In active discussions
~3.5 bcfd	~2.5 bcfd	~17 years	~2-4+ bcfd

Also deliver ~1 bcfd of producer / marketer supply



Beyond the Backlog

Strong long-term fundamentals to drive additional opportunities

Infrastructure to support U.S. energy exports

Northeast natural gas demand & long-term supply needs

Storage to support renewable power generation & LNG exports

Natural gas for power generation

Organic growth in G&P

Market access for surging Permian Basin production

Transport natural gas to supply LNG exports

Expect $2-3 billion of growth capital / year,
consistent with historical spending throughout multiple cycles.
To the extent we don't, multiple options for returning value to investors.

Prioritizing Environmental, Social & Governance (ESG)

Protecting the public, our employees & the environment

- Invest millions of dollars each year on integrity management & maintenance programs to operate our assets safely
  - Outperform the industry averages in almost all safety & release related categories
- Employ sustainable business practices, conduct ourselves in an ethical & responsible manner
  - Our Code of Business Conduct & Ethics outlines our commitment to integrity, accountability, safety & excellence
  - We expect our employees to uphold these standards at work every day
- Support the communities where we work
  - Donate more than $1 million annually to academic & arts programs through the Kinder Morgan Foundation

Doing business the right way, every day

SUSTAINALYTICS ESG RISK RATING(a)

#2 out of 184	Refiners & Pipelines (Industry Group)
#2 out of 102	Oil & Gas Storage & Transportation (Subindustry)

Surpassed methane emissions intensity target(b) in 2018

0.02% vs. 0.31%

target for natural gas transmission & storage assets

7

years ahead of schedule

a) As of 12/20/2019.
b) Kinder Morgan's allocation of One Future methane emissions intensity target.

Contributing to a Lower-Carbon Future with Natural Gas

Long-standing commitment to reducing methane emissions | Ongoing enhancements to ESG disclosures

- 25+ years of commitment to reducing methane emissions, including ONE Future & EPA's Natural Gas STAR program
- Rated in top quartile of midstream sector for methane disclosures & quantitative methane targets by Environmental Defense Fund
- Released second ESG Report, including 2 degree scenario analysis in 2019 ESG report
- Utilizing Sustainability Accounting Standards Board (SASB) & Task Force for Climate-Related Disclosure (TCFD) frameworks
- Multiple ongoing energy management programs to reduce our electricity usage & Scope 2 GHG emissions

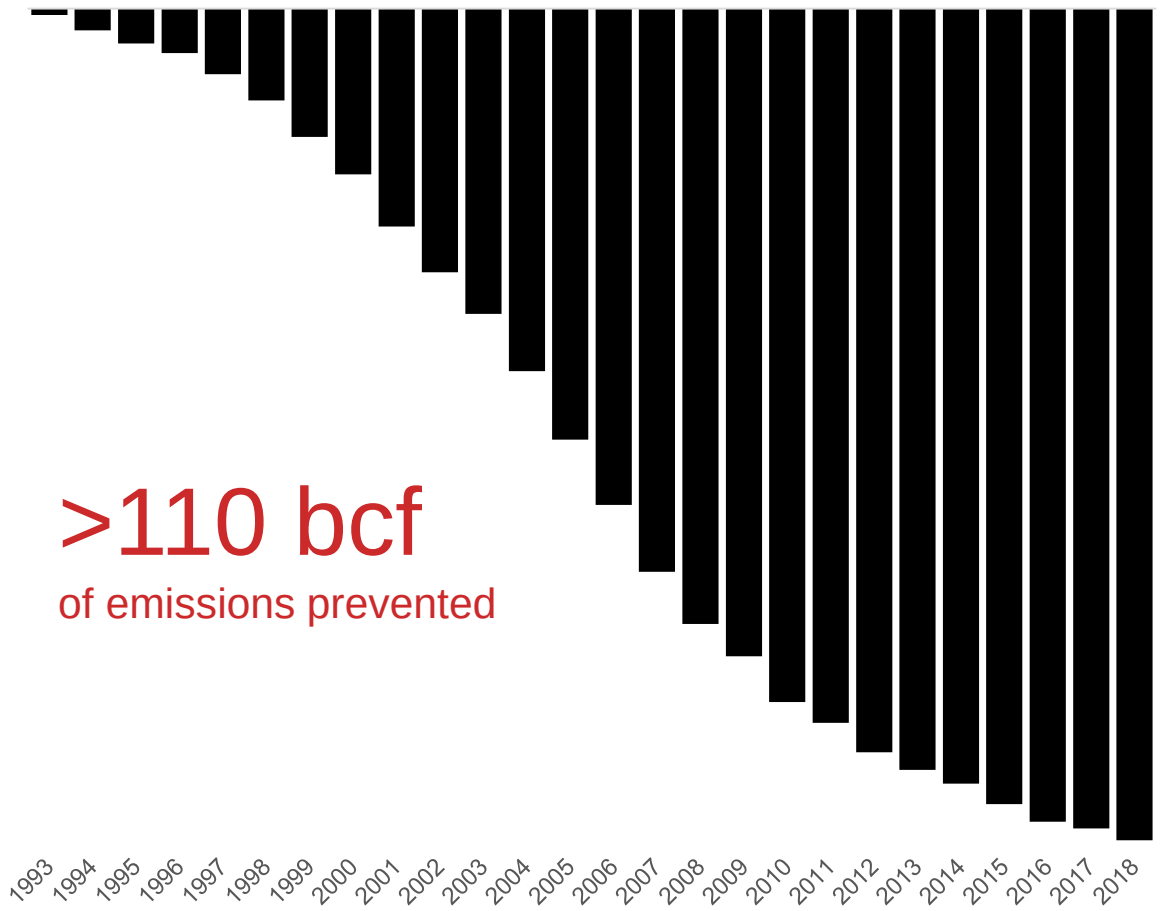
ECONOMICALLY INCENTIVIZED TO REDUCE EMISSIONS

Savings from reducing pipeline blowdowns ($ millions)

		Estimated reductions	Savings value @ $3/Mcf	Project cost	CO2e emission reductions
2017	113 projects	1.9 bcf	$5.6	$3.6	846,783 tons
2018	90 projects	1.6 bcf	$4.8	$3.1	724,798 tons

SUCCESSFUL METHANE EMISSIONS REDUCTIONS[a]

bcf, cumulative across KM operations



a) Kinder Morgan's EPA Natural Gas STAR Summary Report (September 2019).

Business Review

Kimberly Dang

President

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:	659	bcf

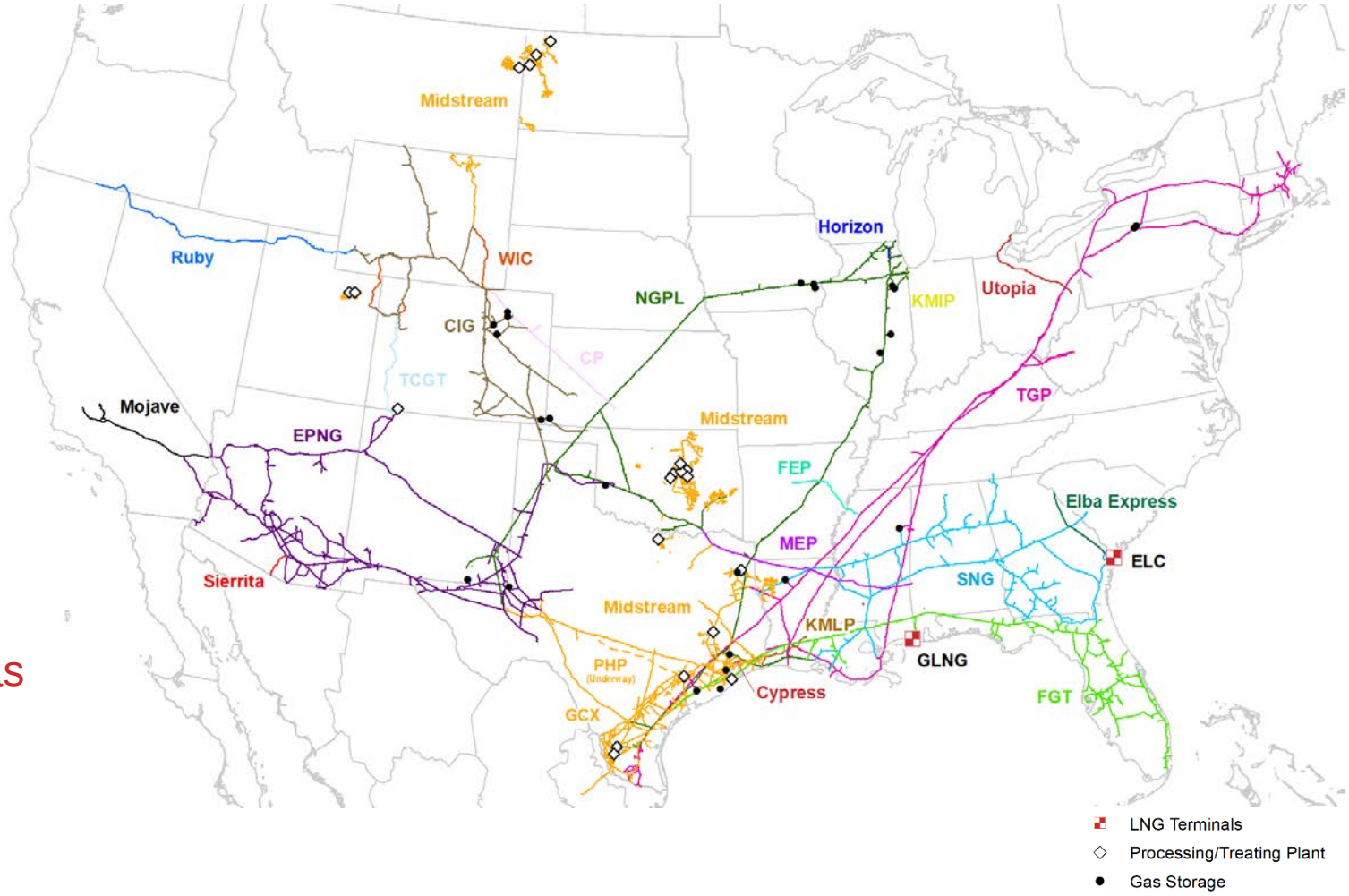
2020B EBDA[(a)]: $4.7 billion

Project Backlog[(b)]: $2.4 billion

Generates over 60% of KMI earnings & contributes nearly 70% of backlog

Connects effectively all major supply areas to key demand centers across the U.S.

Attractive expansion opportunities from significant existing footprint



a) 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
b) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

Long-Term Growth Drivers: Natural Gas Segment

Capitalizing on industry trends

Exports	▪ LNG exports: pipeline infrastructure & liquefaction facilities ▪ Exports to Mexico: additional volume with ramp up of in-country infrastructure ▪ Outlets for growing Permian supply from GCX & PHP
Shale-driven expansions / extensions to serve associated & dry gas growth	▪ Leveraging off of existing footprint (Permian, Bakken) ▪ Greenfield projects
Storage & linepack support for increasingly variable demand	▪ LNG export interruptions (e.g., due to weather, maintenance) ▪ Complement variable renewable generation with responsive gas deliverability ▪ Support daily & seasonal variability in exports to Mexico ▪ Meet peak demand periods in summer & winter
Gulf Coast petrochemical & other industrial demand	▪ Strategic pipeline footprint & storage to serve growing demand ▪ Established deliverability into major markets
Pipeline conversions & reversals	▪ Repurpose assets to maximize value of pipe in the ground ▪ Brownfield solutions in increasingly challenging market for new construction
Operating leverage	▪ Capture price volatility & deliverability needs with storage / linepack ▪ Tailor premium services to leverage operational flexibility
End-user / LDC demand growth	▪ Regional power generation opportunities, baseload growth & peaking ▪ Unique last-mile connectivity to LDC markets

Products Segment Overview

Strategic footprint with significant cash flow generation

Asset Summary

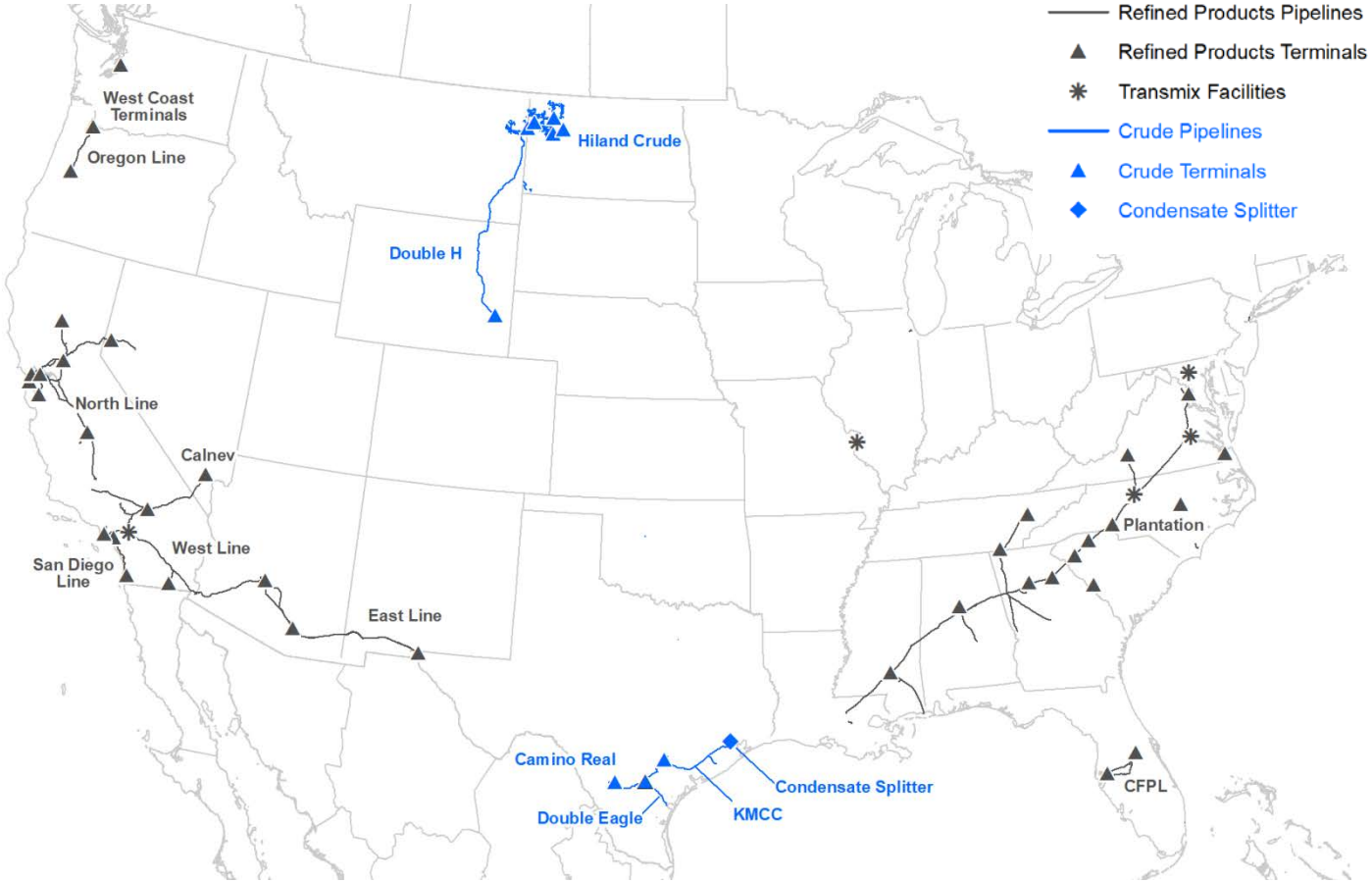
Pipelines[a]:	~9,500	miles
2019 throughput[a]	~2.4	mmbbld
Terminals:	65	terminals
Terminals tank capacity	~39	mmbbls
Pipeline tank capacity	~16	mmbbls
Condensate processing capacity	100	mbbld
Transmix	5	facilities

2020B EBDA[b]: $1.3 billion

Project Backlog[c]: $0.2 billion

Volume growth consistently outpaces national average

Steady volume growth & indexed tariff escalators provide revenue upside

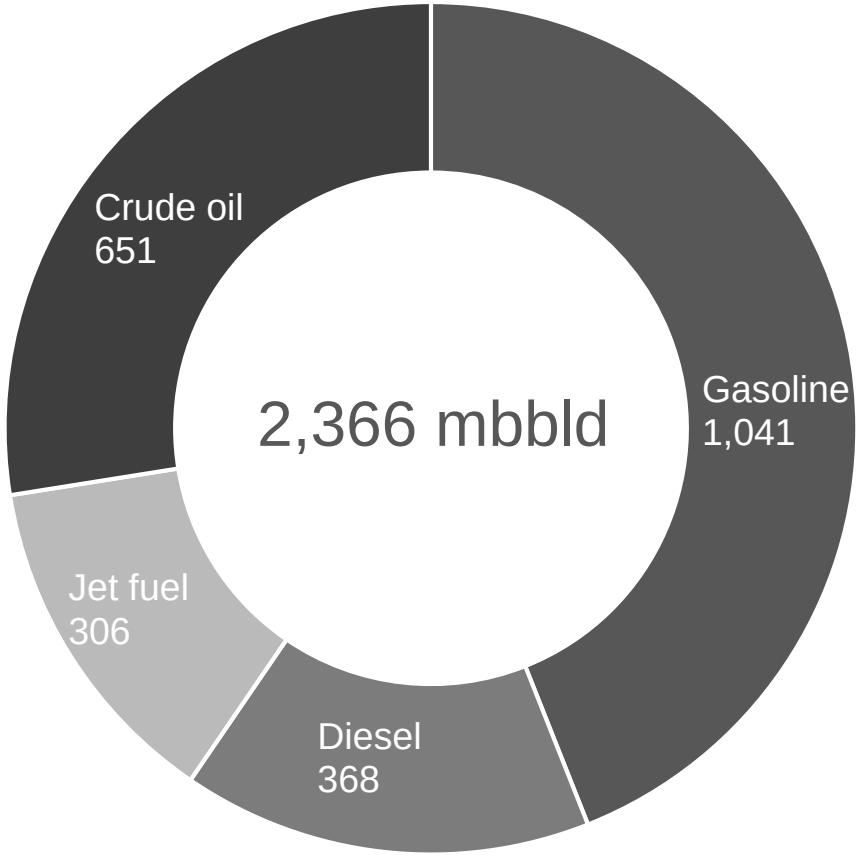


a) Volumes include SFPP, CALNEV, Central Florida, Plantation Pipe Line (KM share), KMCC, Camino Real, Double Eagle (KM share), Double H & Hiland Crude Gathering.
b) 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
c) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

Products Segment Overview

Supplying a diverse mix of feedstock & finished products critical to refining & transportation sectors

2019 DELIVERY VOLUMES[a]



Gasoline	■ Robust economy & consumer preference supports demand growth partially offset by improving fuel efficiency ■ EIA projecting 0.2% growth in 2020[b] ■ Volume by region[c]: Southeast 26% & West 74%
Diesel fuel	■ EIA projecting 0.8% growth in 2020[b] ■ Volume by region[c]: Southeast 22% & West 78%
Jet fuel	■ EIA projecting 1.2% growth in 2020[b] ■ Airports supplied include Atlanta, Las Vegas, Orlando, San Francisco & Washington D.C. ■ Volume by region[c]: Southeast 18% & West 82%
Crude oil	■ Positioned in premier basins in both Texas & N. Dakota ■ KMCC provides access to Houston refining market & export for both Eagle Ford & Permian production ■ Hiland is one of the Bakken's premier gathering systems ■ Double H provides takeaway capacity from the Bakken to Cushing via joint tariff ■ Volume by region[d]: Texas 49% & Bakken 51%

a) Kinder Morgan volumes include SFPP, CALNEV, Central Florida, Plantation Pipe Line (KM share), KMCC, Camino Real, Double Eagle (KM share), Double H & Hiland Crude Gathering; Gasoline volumes include ethanol.
b) U.S. consumption volumes per EIA, Short-term Energy Outlook Table 4a, December 2019.
c) Southeast Region Assets include Central Florida & Plantation Pipe Line(KM share); West Region includes SFPP & CALNEV.
d) Texas Crude Assets include KMCC, Camino Real, Double Eagle(KM share); Bakken Crude includes Double H & Hiland Crude Gathering.

Consumer Preferences Suggest Product Demand Growth

Both U.S & global demand trending higher

EV MARKET SHARE

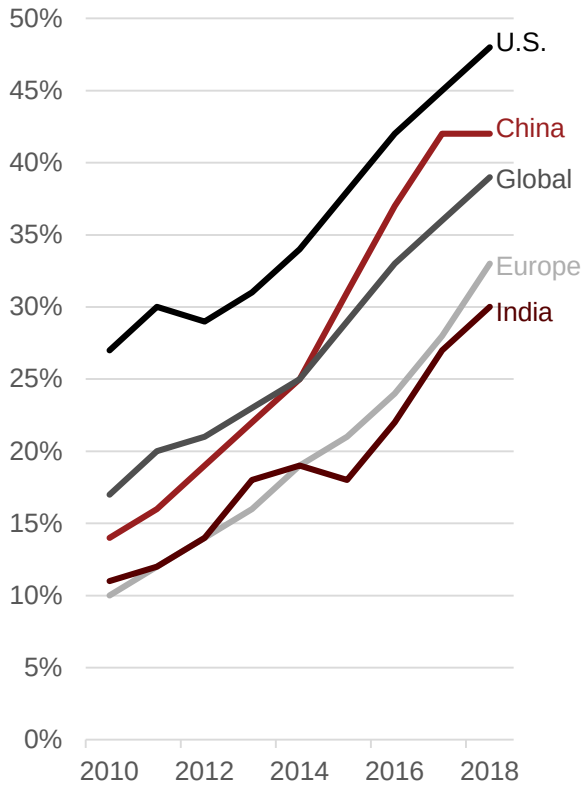
2018 global car sales by manufacturer

Top carmakers[a]	EVs as % of sales	EVs sold (000s)
Toyota	0.6%	48
Renault-Nissan	2.2%	150
Hyundai-Kia	1.2%	82
Volkswagen	0.8%	52
Ford	0.2%	10
Honda	0.4%	20
Chevrolet (GM)	1.3%	48
Suzuki	0.1%	3
Mercedes (Daimler)	1.5%	38
SAIC	4.1%	98
BMW	6.4%	128
Audi	0.9%	16
Top carmaker total	1.3%	693

EVs only ~1% of global sales vs. targets of 15-25% by 2025

SUV MARKET SHARE

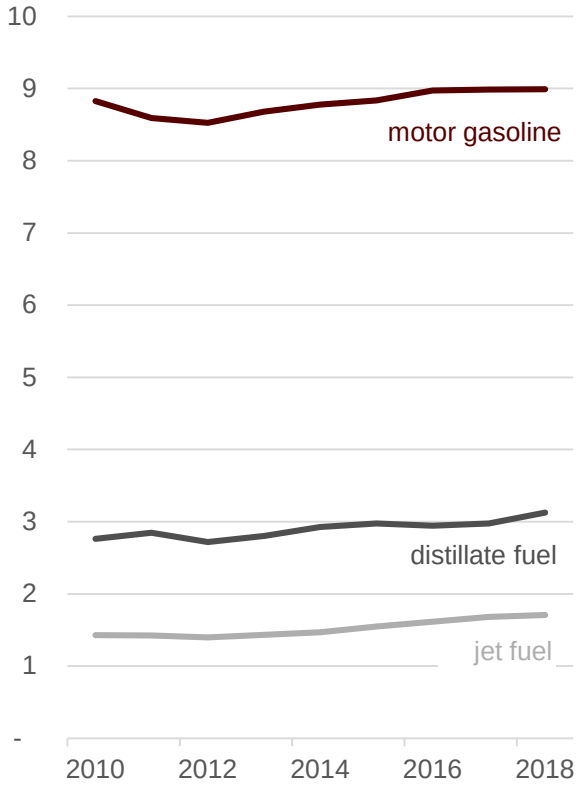
% of sales in key car markets



SUVs gaining market share around the world

U.S. TRANSPORTATION DEMAND

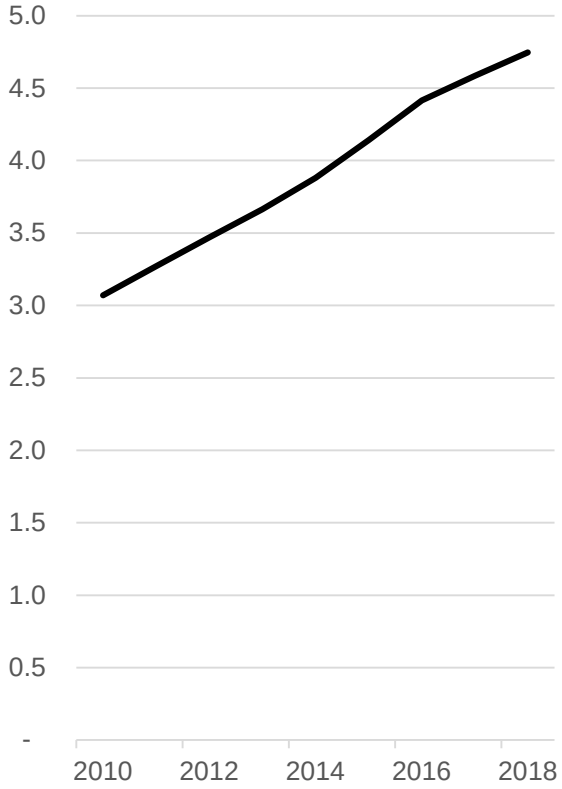
million barrels per day



Steady increases in U.S. demand for major transportation fuels

GLOBAL AIR TRAVEL

trillion revenue-passenger-miles



Meaningful global growth in passenger air travel

Source: International Energy Agency, World Energy Outlook, November 2019 (Stated Policies Scenario), U.S. Energy Information Administration

a) Carmakers ranked by # of vehicles sold per IEA. List of manufacturers shown sold ~54 million cars globally in 2018. Tesla produced 255k & delivered 246k vehicles in total in 2018 (per 10-K filed with the SEC).

Terminals Segment Overview

Diversified terminaling network connected to key refining centers & market hubs

Asset Summary	# of terminals	capacity (mmbbls)
Terminals Segment – Bulk	32	
Terminals Segment – Liquids	50	79
Products Pipelines Segment	65	55
Total	147	134
Jones Act:	16 tankers	

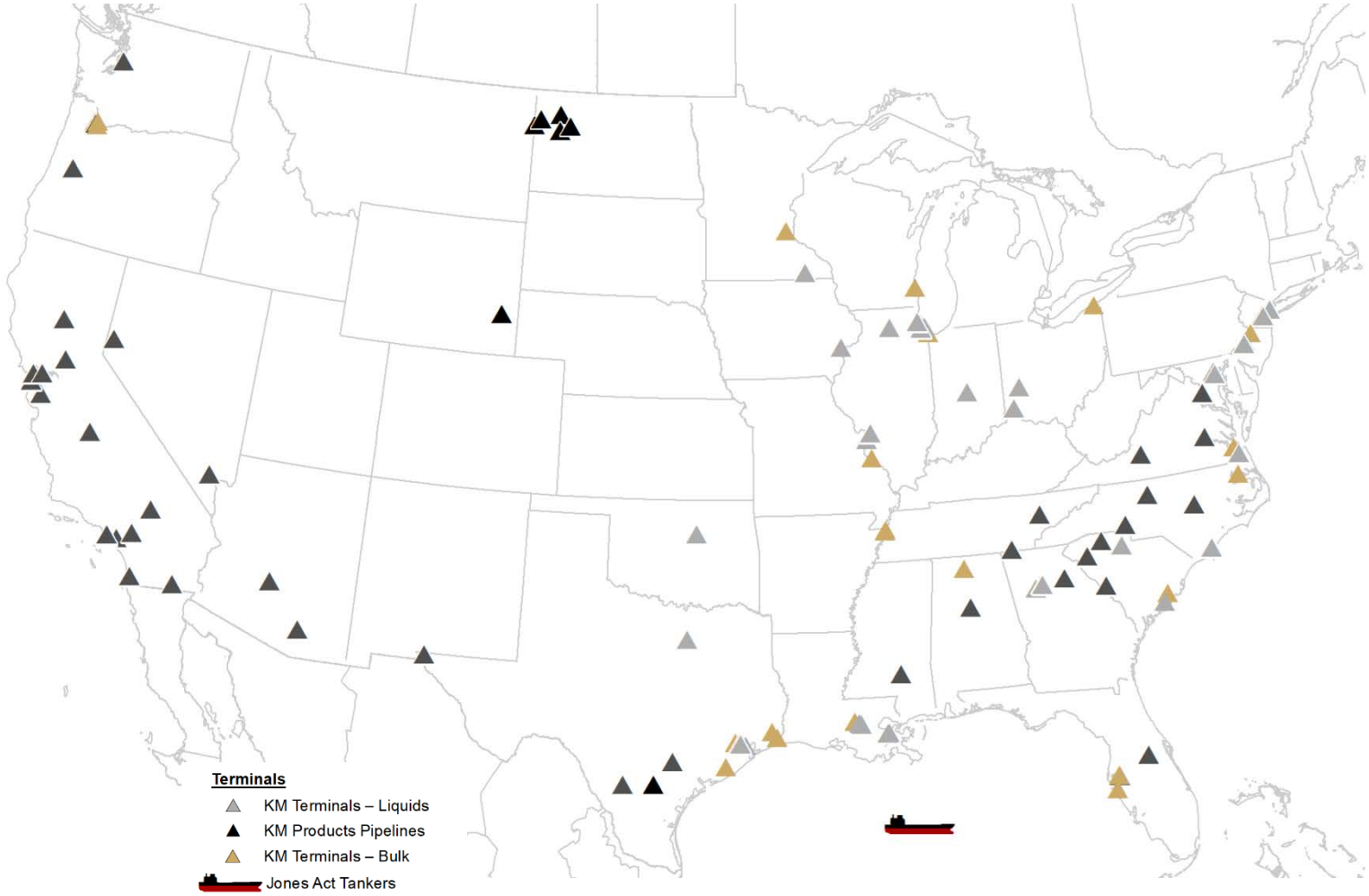
2020B EBDA[(a)]: $1.1 billion

Project Backlog[(b)]: $0.2 billion

Diverse, liquids-focused product mix

Earnings driven by long-term contractual use of our assets

Unmatched capabilities on the Houston Ship Channel



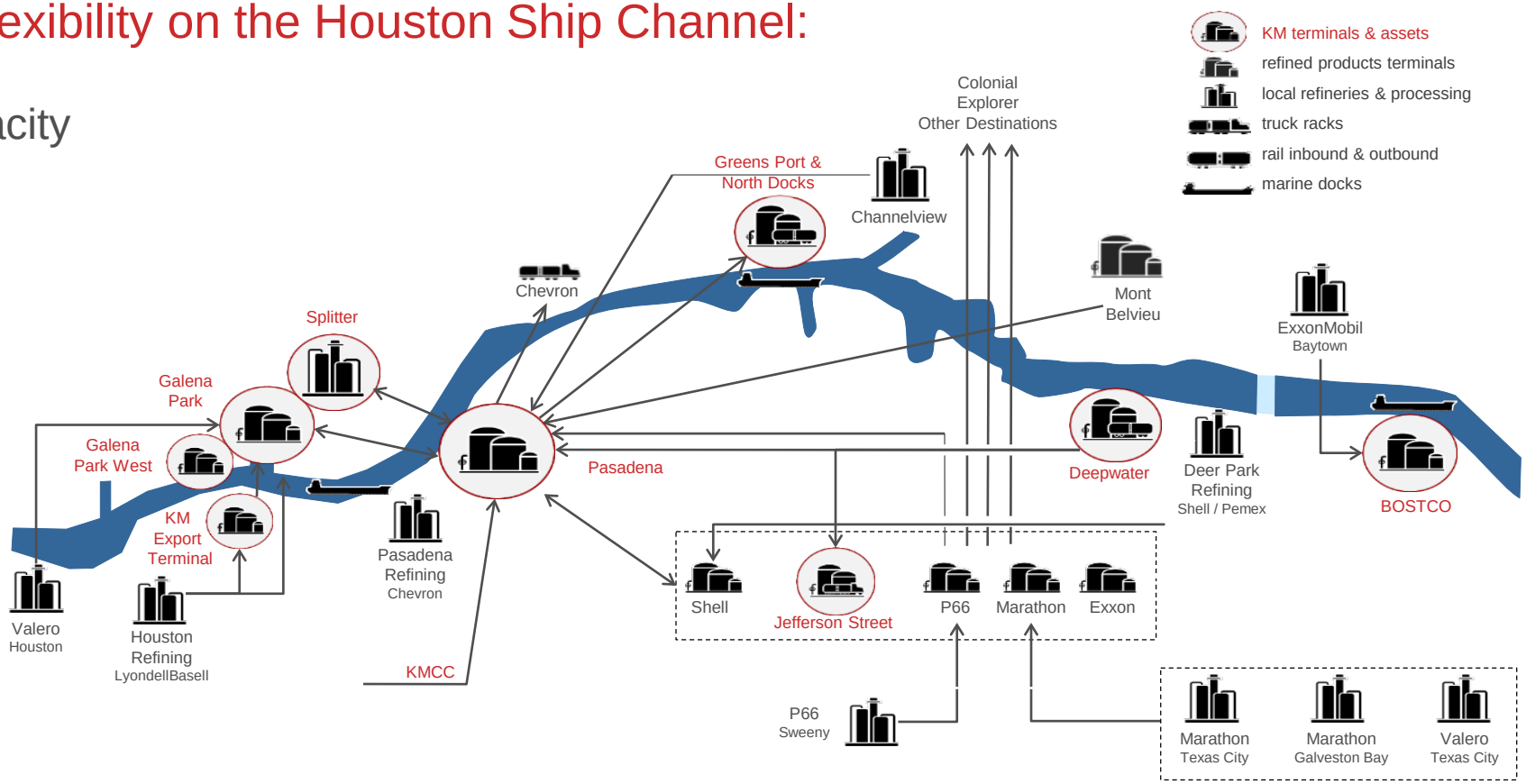
a) 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
b) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

Integrated Terminaling Network Focused on Refined Products

Irreplaceable collection of assets, capabilities & market-making connectivity

Our unmatched scale & flexibility on the Houston Ship Channel:

- **43** million barrels total capacity
- **29** inbound pipelines
- **18** outbound pipelines
- **16** cross-channel pipelines
- **11** ship docks
- **38** barge spots
- **35** truck bays
- **3** unit train facilities



~$2.0 billion invested since 2010

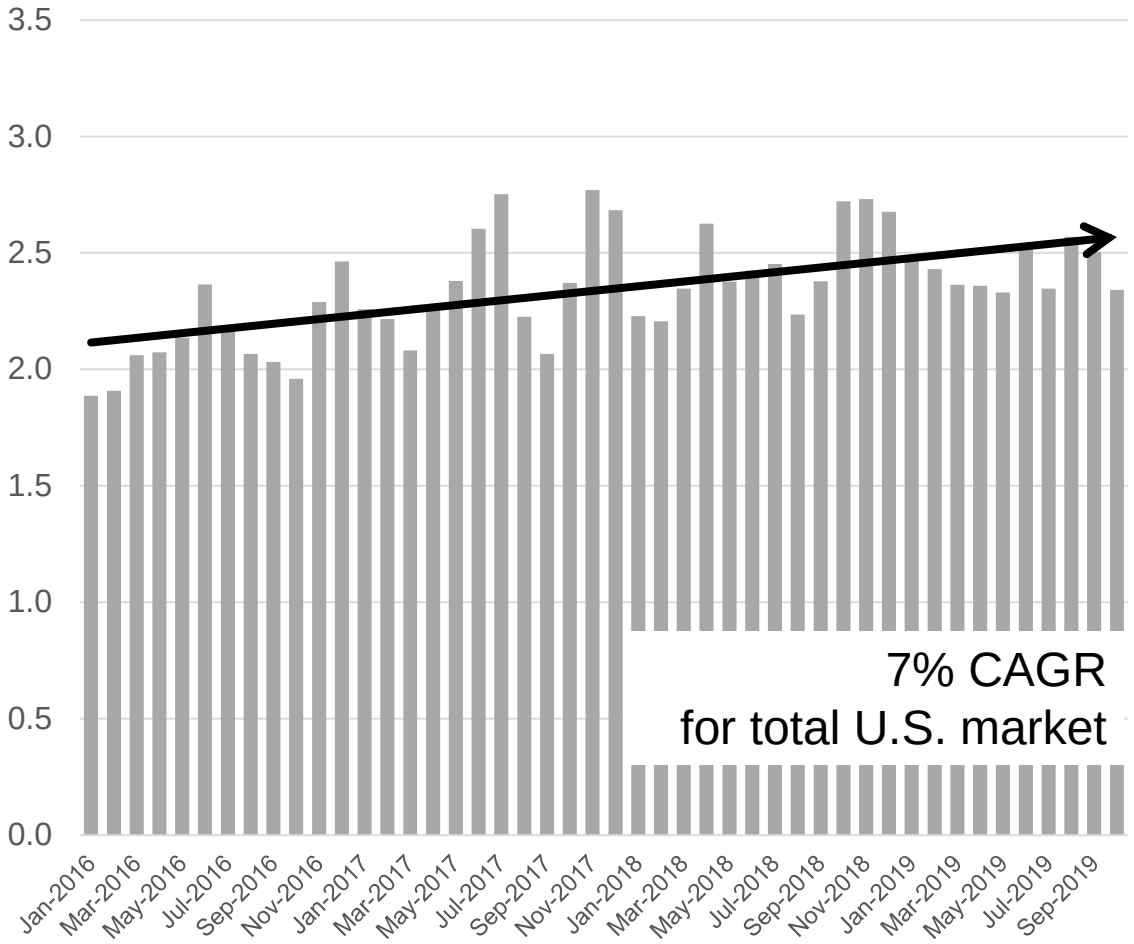
Note: asset metrics include projects currently under construction

Leading Exporter of U.S. Gasoline & Distillates

Our Houston Ship Channel exports have grown faster than the broader U.S. market over the last several years

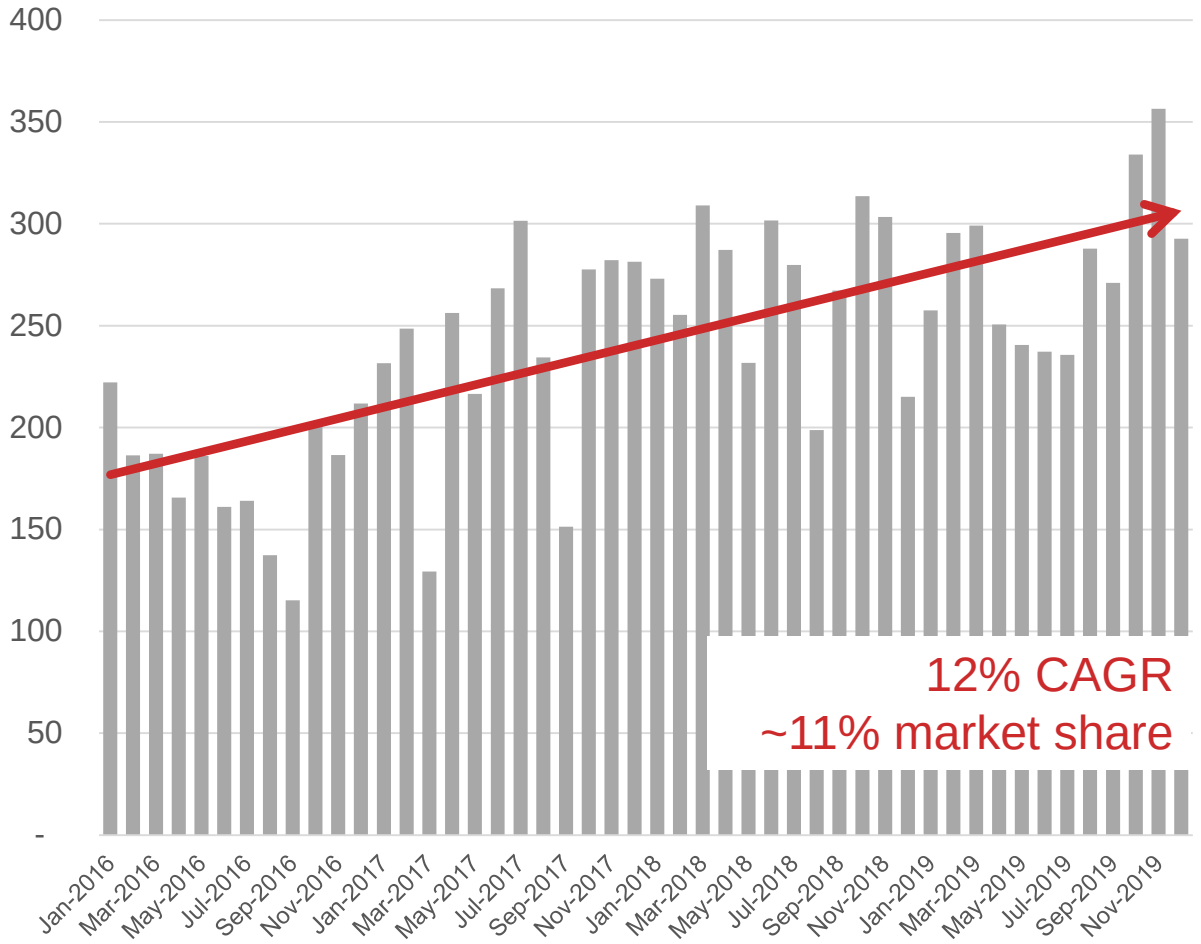
U.S. EXPORTS

Millions of barrels per day



KM EXPORTS FROM HOUSTON SHIP CHANNEL

Thousands of barrels per day



Source: U.S. Energy Information Administration, KM internal data

Note: Charts include distillate fuel oil, finished motor gasoline, gasoline blending components & jet fuel. CAGR calculated on a rolling 3-months basis beginning Q1 2016. KM market share calculated using internal data for KM export volumes & U.S. Energy Information Agency for U.S. export volumes for the 12 months ended October 2019 (latest EIA data available).

CO_2 Segment Overview

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

CO_2 Reserves	KMI Interest	NRI	Location	Est. OGIP (tcf)
McElmo Dome	45%	37%	SW Colorado	22.0
Doe Canyon	87%	68%	SW Colorado	3.0
Bravo Dome[a]	11%	8%	NE New Mexico	12.0

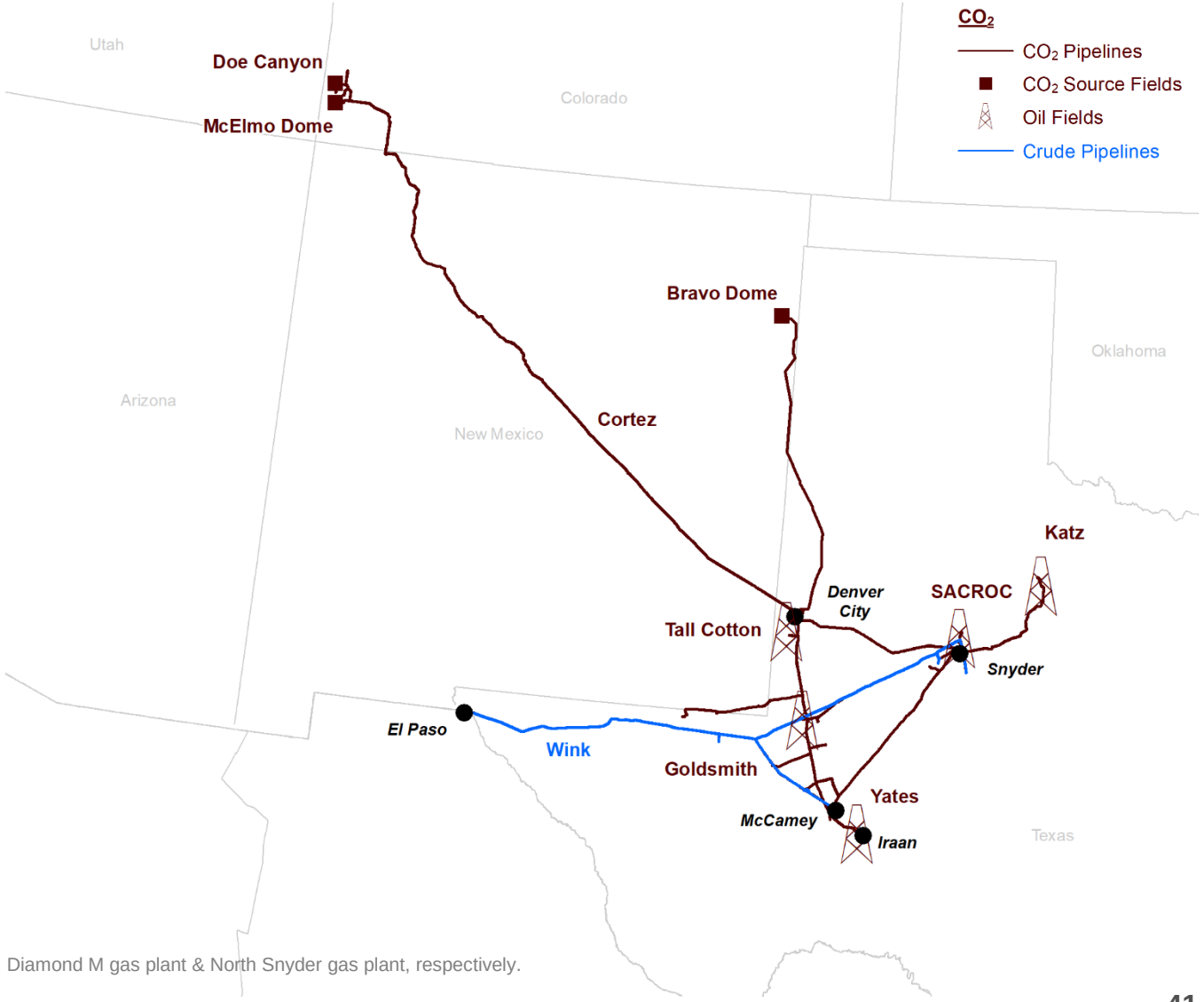
Crude Reserves[b]	KMI Interest	NRI	Location	Est. OOIP (billion bbls)
SACROC	97%	83%	Permian Basin	2.8
Yates	50%	44%	Permian Basin	5.0
Katz	99%	83%	Permian Basin	0.2
Goldsmith	99%	87%	Permian Basin	0.5
Tall Cotton	100%	88%	Permian Basin	0.7

2020B EBDA[c]: $763 million

Project Backlog[d]: $0.8 billion

Substantial remaining oil reserves

Transition Zone has potential to add 700 mmbbls OOIP to SACROC



Note: OGIP = Original Gas In Place. OOIP = Original Oil In Place.

a) Not KM-operated.

b) In addition to KM's interests above, KM has 22%, 51% & 100% working interests in the Snyder gas plant, Diamond M gas plant & North Snyder gas plant, respectively.

c) 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

d) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

CO_2 Free Cash Flow & Attractive Returns

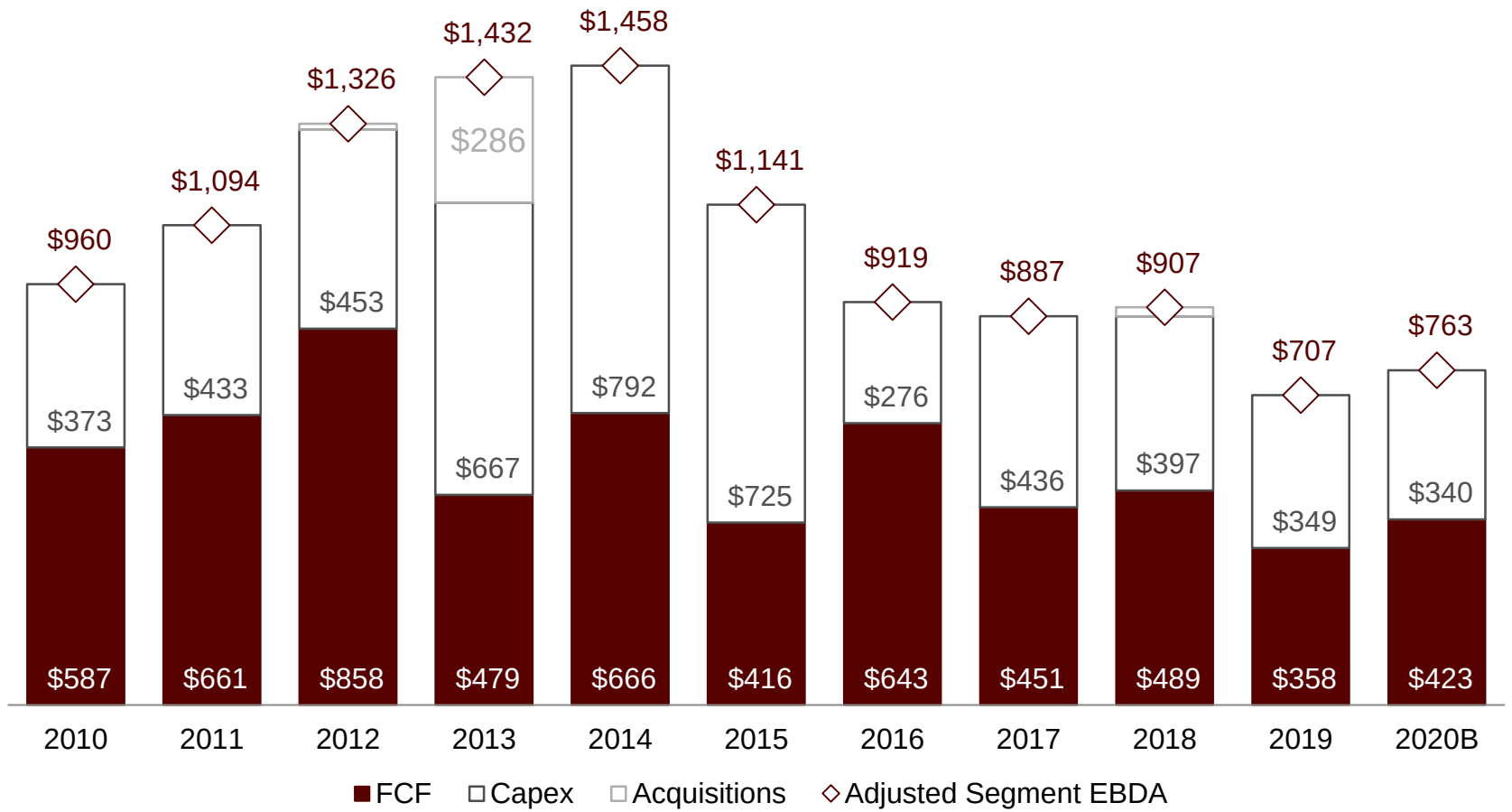
Long history of generating high returns & significant CO_2 free cash flow with minimal acquisitions

CO_2 IRR% 2000-2019

Oil & Gas	18%
Total CO_2 Segment (incl. CO_2 & transport)	28%

SIGNIFICANT CO_2 FREE CASH FLOW

$ millions

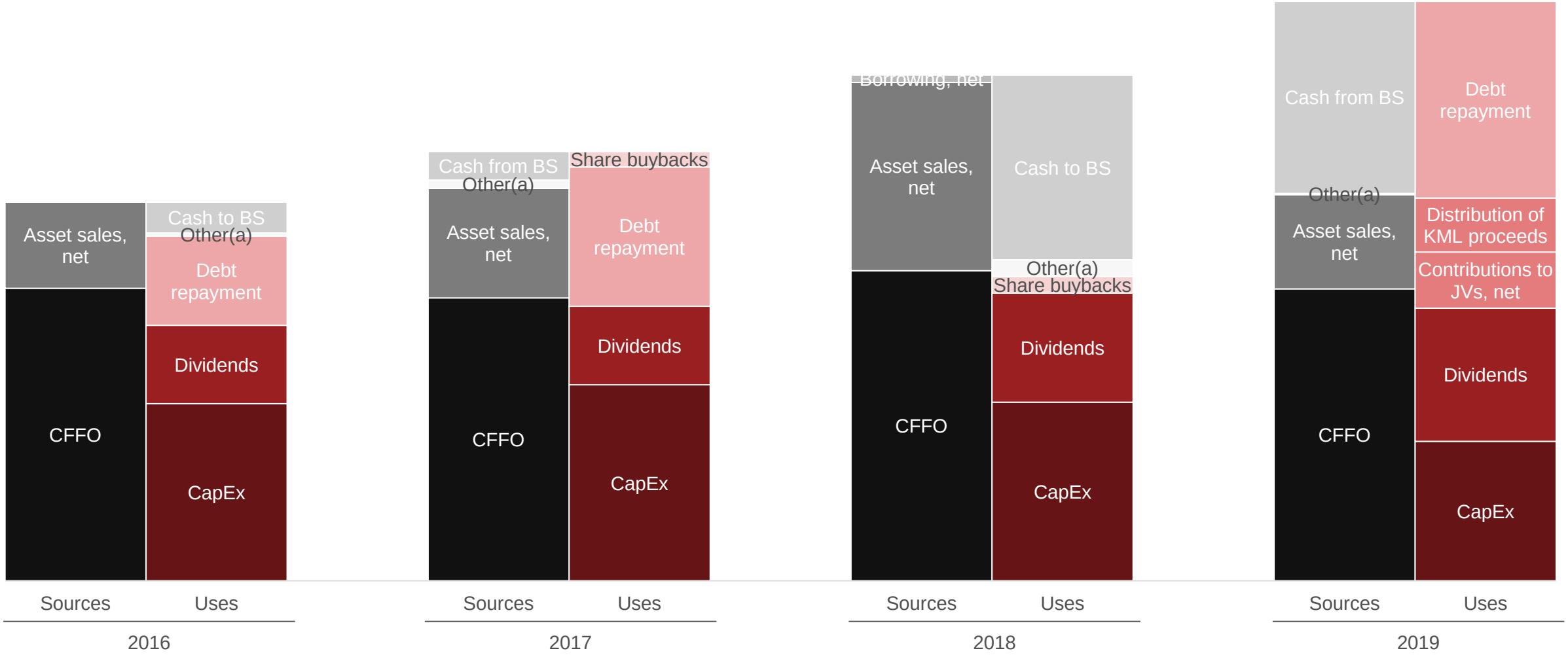


Note: CO_2 Internal Rate of Return (IRR) & CO_2 Free Cash Flow. See Non-GAAP Financial Measures & Reconciliations.

Significant & Stable Cash Flow Generation

Opportunistic asset monetization enabled meaningful debt reduction

Self-funded all capex & all dividends with >$19 billion of cash flow from operations since 2016



Source: GAAP Statement of Cash Flows

Note: "Asset sales, net" include the monetization of a 50% interest in Southern Natural Gas, Kinder Morgan Canada Limited (KML IPO & sale), Trans Mountain pipeline & U.S. Cochin pipeline.

a) "Other" includes (i) net contributions to JVs, (ii) distributions in excess of cumulative earnings from JVs, (iii) net distributions to NCI (except for 2019, where these items are shown separately), (iv) the effect of FX on cash & (v) other, net.

Incremental 2020B Cash Flow Returned to Shareholders

Multiple attractive capital allocation opportunities

$2.7 billion excess cash flow

- $5.1 billion of DCF less $2.4 billion of discretionary capital

less

$2.7 billion dividend paid

- 25% increase planned for 2020
- dividend paid entirely out of cash flow

plus

$1.2 billion balance sheet

- expected to end 2020 with 4.3x leverage
- long-term target of ~4.5x net debt / Adjusted EBITDA
- incremental balance sheet capacity available to create additional value

implies

$1.2 billion available for **Share buybacks** or **Capital projects** or **Retained balance sheet capacity**

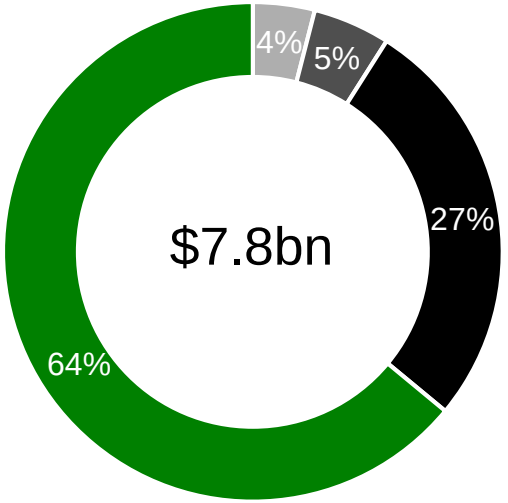
All options evaluated regularly to maximize shareholder value

See Non-GAAP Financial Measures & Reconciliations.

Stable, Fee-Based Cash Flow from High Quality Customers

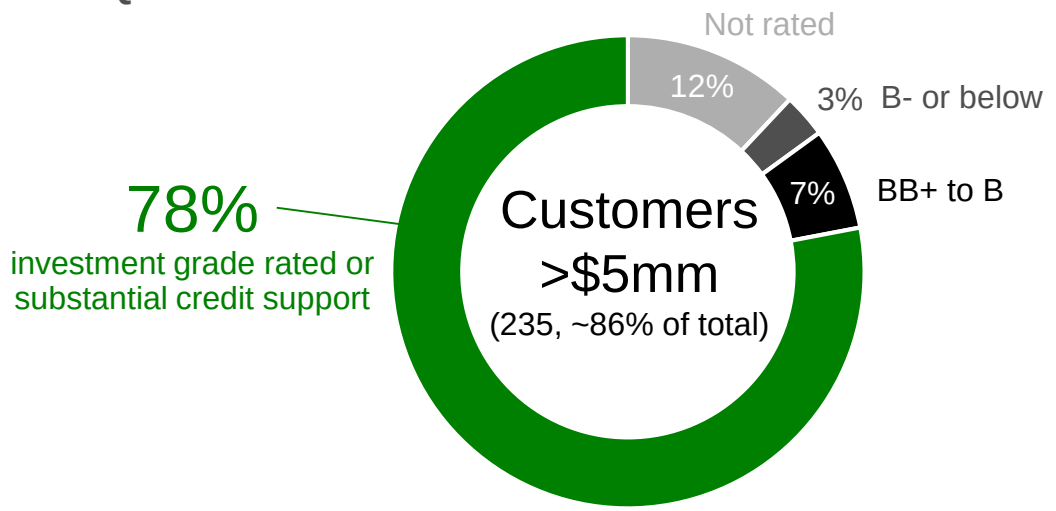
Underpinned by multi-year contracts with diversified customer base

STABLE CASH FLOWS[a]



64% Take-or-pay	Entitled to payment regardless of throughput
27% Fee-based	Supported by stable volumes, critical infrastructure between major supply hubs & stable end-user demand
5% Hedged	Disciplined approach to managing price volatility, substantially hedged near-term exposure
4% Other	Commodity-price based, limited to small portions of unhedged oil & gas production & G&P business

HIGH QUALITY CUSTOMERS[b]



plus:

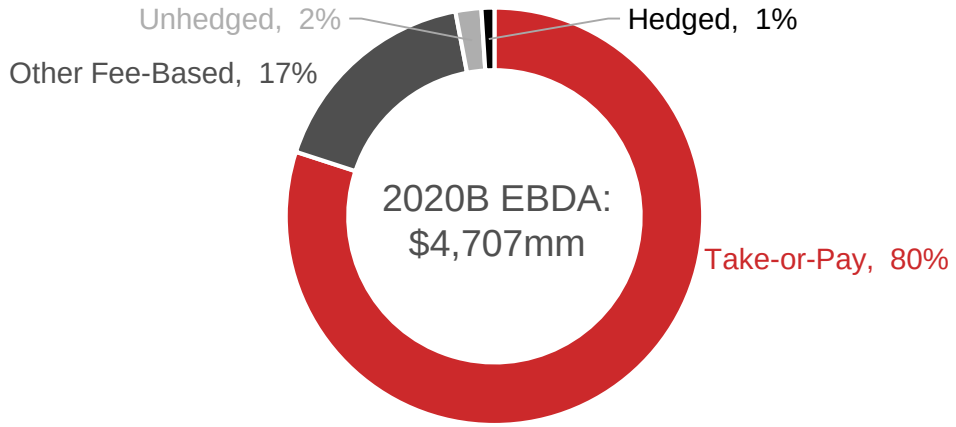
~71% of net revenue comes from end-users of the products we handle

a) Based on 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
b) Based on 2020 budgeted net revenues, which include our share of unconsolidated joint ventures & net margin for our Texas Intrastate customers & other midstream businesses. Chart includes customers >$5mm at their respective company credit ratings as of 1/23/2020 per S&P & Moody's, shown at the S&P-equivalent rating & utilizing a blended rate for split-rated companies. End-users includes utilities, LDCs, refineries, chemical companies, large integrateds, etc.

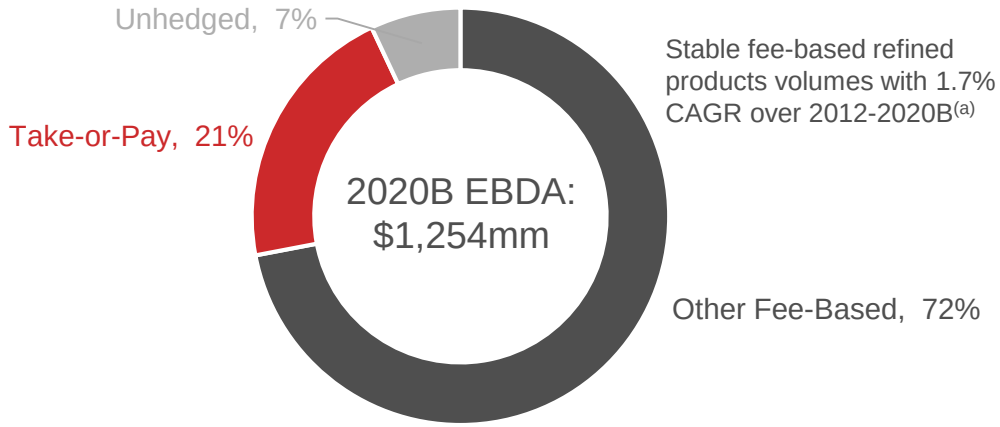
Secure Cash Flows Across Our Segments

2020 budgeted segment cash flows by contract type

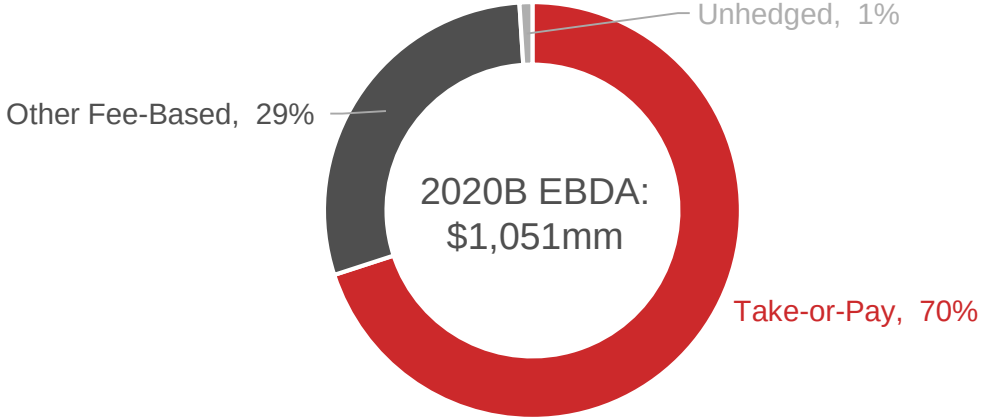
NATURAL GAS SEGMENT: 97% take-or-pay or fee-based



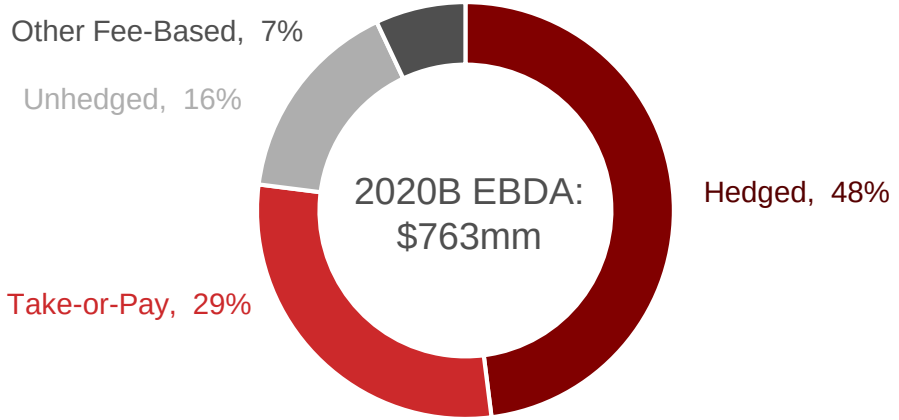
PRODUCTS SEGMENT: 93% fee-based or take-or-pay



TERMINALS SEGMENT: 99% take-or-pay or fee-based



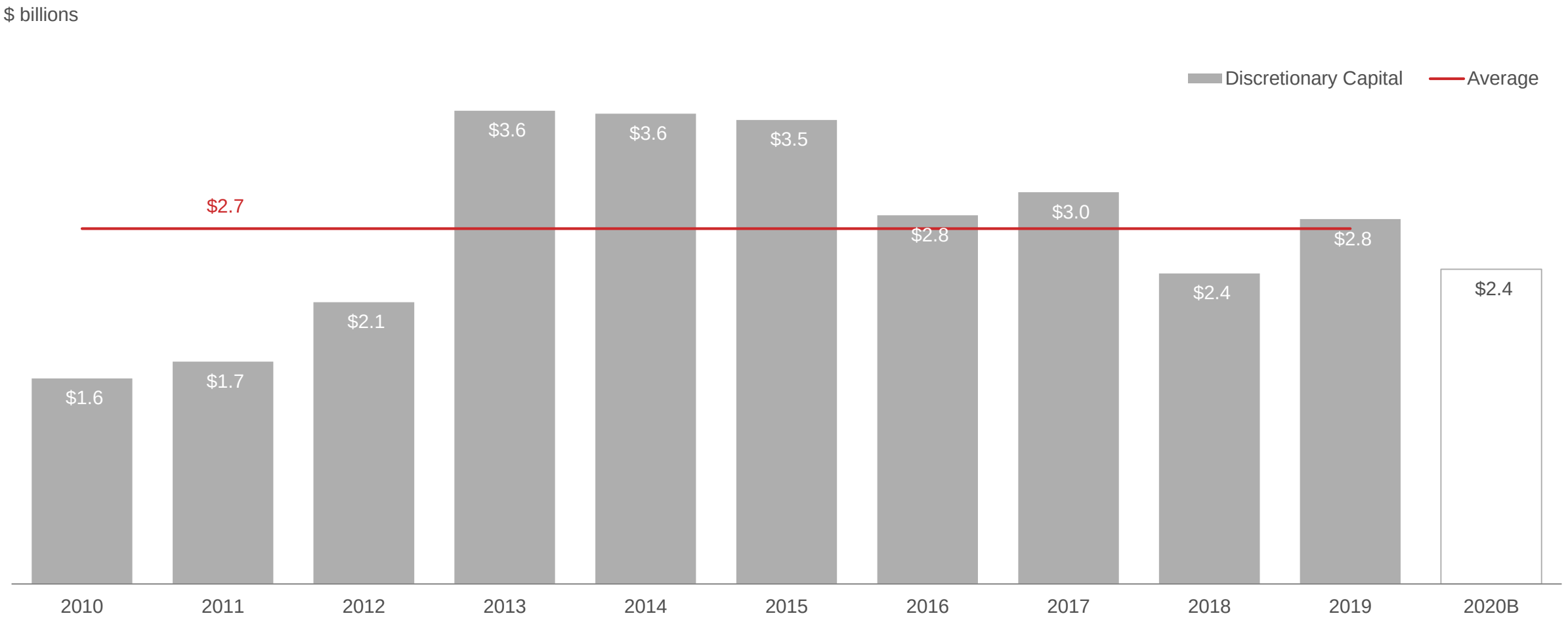
CO_2 SEGMENT: 84% hedged, take-or-pay, or fee-based



Note: Based on 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
a) Volumes include SFPP, CALNEV, Central Florida, Plantation Pipe Line (KM share).

Historical Discretionary Capital Spending Levels

Averaged $2.7 billion per year since 2010



We will retain our capital discipline – if projects don't meet our returns, we will create value in other ways

Note: Discretionary capital includes small acquisitions & equity contributions to joint ventures which may include debt repayments. Includes KMP (2008-2014), EPB (2013-2014) & KMI (2015-2020B). Average from 2010-2019. Excludes capital expenditures of our Canadian assets from KML IPO (May 2017) through KML divestiture (December 2019).

Successfully Achieving Attractive Build Multiples

Established track record of leveraging our footprint & project management expertise

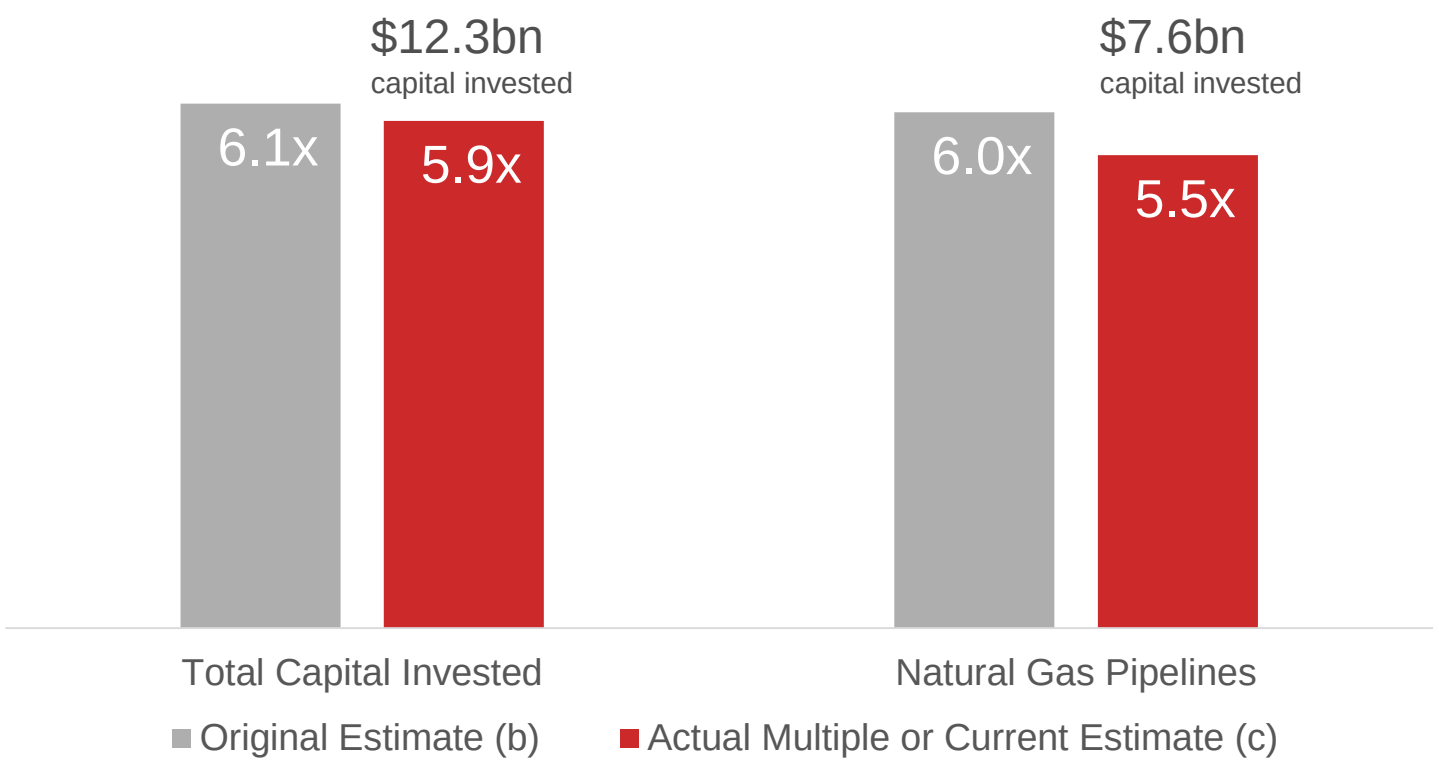
Competitive advantages:

- Expansive asset base — ability to leverage or repurpose steel already in the ground
- Connected to practically all major supply sources
- Established deliverability to primary demand centers — final mile builds typically expensive to replicate due to congestion
- Strong balance sheet & ample liquidity — internal cash flow available to fund nearly all investment needs

Expansive footprint creates opportunities for differentiated returns

INVESTMENT MULTIPLES: PROJECTS COMPLETED 2015-2019

Capital invested / year 2 Project EBITDA[(a)]



Note: See Non-GAAP Financial Measures & Reconciliations. Includes certain projects placed in commercial service prior to 2015, but were still under construction.

a) Multiple reflects KM share of invested capital divided by Project EBITDA generated in its second full year of operations. Excludes CO_2 segment projects.

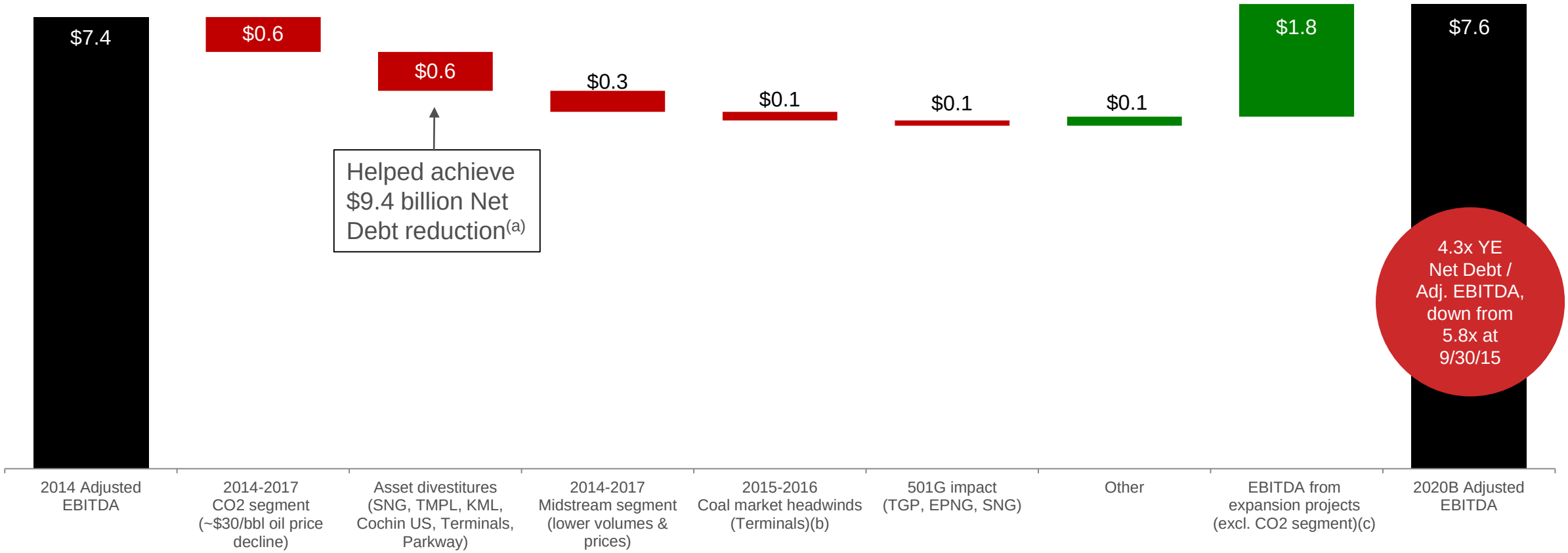
b) Original estimated capital investment divided by original estimated Project EBITDA for project in its second year of operation.

c) Actual capital invested (except for 3 projects which are partially in service & represent $88mm of capex spend beyond 2019) divided by actual or currently estimated Project EBITDA. Natural gas segment multiple includes Elba liquefaction project, for which partial sale of interest & contractual protections at Elba mitigated returns from original model despite in-service delay.

Stable Foundation of Cash Flows through Commodity Cycles

6-year change in Adjusted EBITDA

$ billions



Consistently generated **over $7 billion of Adjusted EBITDA each year** through multiple market disruptions & significant strategic efforts, including asset sales & deleveraging

Note: See Non-GAAP Financial Measures & Reconciliations. Reconciliation for 2014 Adjusted EBITDA provided in 2015 Analyst Day slide deck available on Kinder Morgan website.

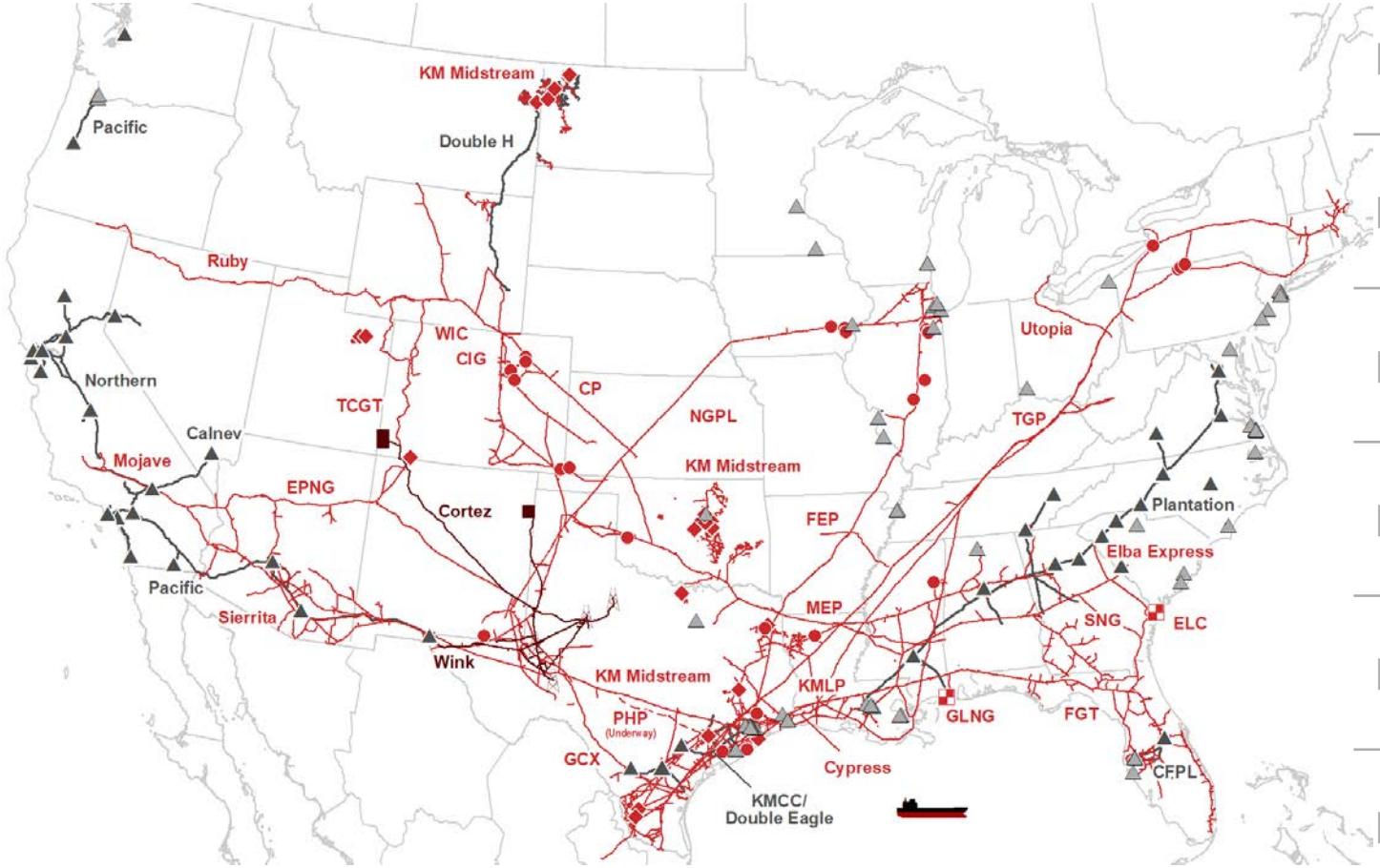
a) Change in consolidated Adjusted Net Debt from 9/30/2015 through 12/31/2019.

b) Headwinds during 2015 & 2016 in coal market led to bankruptcy filings of three of our largest customers & the cancellation of a contract.

c) Excludes EBITDA growth for KML & Cochin US from 2014 through 2019 (year of sale).

Compelling Investment Opportunity

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



- >90% take-or-pay or fee-based earnings[(a)]
- ~$7.6 billion 2020B Adjusted EBITDA[(b)]
- ~5% current dividend yield
- 25% budgeted dividend increase in 2020
- Highly-aligned management (15% stake)
- Active stock buyback program

Market sentiment may change, but we'll stay focused on making money for our shareholders

Note: See Non-GAAP Financial Measures & Reconciliations.
a) Based on 2020B Adjusted Segment EBDA.
b) Please refer to "2020 Guidance – Published Budget" for more detail.

Panel with Business Unit Presidents

Tom Martin	President of Natural Gas
James Holland	President of Products
John Schlosser	President of Terminals
Jesse Arenivas	President of CO_2

2020 Budget

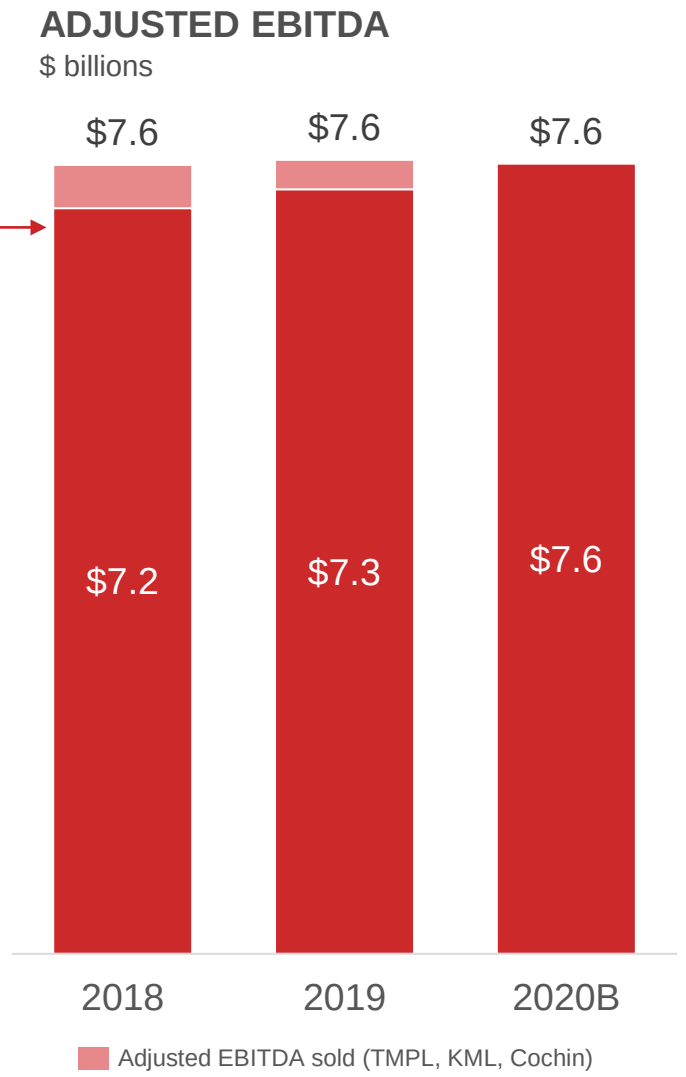
David Michels

Vice President & CFO

2020 Guidance

Published budget

Key Metrics	2020 Budget	change over 2019	
Adjusted EBITDA	$7.6 billion	0%	After normalizing for sold assets, Adjusted EBITDA has grown
Distributable Cash Flow	$5.1 billion	2%	Growth from 2019 despite sale of U.S. Cochin & KML
DCF per Share	$2.24	2%	
Dividend per Share	$1.25	25%	Returning additional value to shareholders via dividend increase
Discretionary Capital[(a)]	$2.4 billion		Historically in the $2-3bn range
Year-end Net Debt / Adj. EBITDA	4.3x		Below 4.5x long-term target, providing attractive financial flexibility



Note: See Non-GAAP Financial Measures & Reconciliations.
a) Includes growth capital & JV contributions for expansion capital, debt repayments & net of partner contributions for our consolidated JVs.

2020B Assumptions & Highlights

	YoY EBDA[a]	KEY DEVELOPMENTS FROM 2019
Natural Gas Pipelines	+2%	– Full year contribution from Elba Liquefaction, GCX & Bakken G&P expansions – TX Intrastates growth projects & increased margin – Sale of Cochin – Unfavorable recontracting impacts (MEP, Ruby) – Lower drilling activity on G&P assets (N. TX, OK, Kinderhawk) – Full year impact of TGP 501G rate settlements
Products Pipelines	0%	– Lower rates on KMCC & Double H contract renewals – ~2% refined product & ~10% crude & condensate volume growth – Bakken & KMCC expansion projects – Refined products: FERC escalator = +1.9%
Terminals	-10%	– Sale of KML (Alberta & Vancouver Wharves terminals) – Contributions from liquids contract rate escalations & Gulf area expansions – Unfavorable recontracting impacts in northeast area
CO_2	+8%	– Improved Midland-Cushing differential hedged price (+$8.22/barrel) – ~8% lower net crude oil production

Interest expense – 3-month LIBOR averages 1.64% for the year, based on approximate forward curve at time of budget

Cash taxes – do not expect to incur any material U.S. federal cash income taxes in 2020

a) Business segment percentage increase / (decrease) is 2020B to 2019A change in Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

2020B Adjusted EBITDA

$ in millions

	2020 Budget	2019 Actual	Change $	Change %
Natural Gas Pipelines	$ 4,707	$ 4,610	$ 97	2%
Products Pipelines	1,254	1,258	(4)	0%
Terminals	1,051	1,174	(123)	-10%
CO_2	763	707	56	8%
Adjusted Segment EBDA[(a)]	**7,775**	**7,749**	**26**	**0%**
General and administrative and corporate charges[(a)]	(590)	(598)	8	-1%
KMI's share of JV DD&A and income tax expense[(a,b,c)]	464	487	(23)	-5%
Net income attributable to NCI[(a)]	(67)	(20)	(47)	237%
Adjusted EBITDA	**$ 7,582**	**$ 7,618**	**$ (36)**	**0%**

Stable Adjusted EBITDA despite sale of KML & U.S. Cochin assets

Note: See Non-GAAP Financial Measures and Reconciliations.

a) Amounts are adjusted for Certain Items.

b) KMI's share of unconsolidated JV DD&A and income tax expense, net of consolidating JV partners' share of DD&A.

c) JV DD&A is not reduced by the noncontrolling interests' portion of KML DD&A of ($19) million in 2019.

2020B Distributable Cash Flow (DCF)

in millions, except per share

	2020 Budget	2019 Actual	Change $	Change %
Adjusted EBITDA	**$ 7,582**	**$ 7,618**	**$ (36)**	**0%**
Interest, net[a]	(1,690)	(1,816)	126	-7%
Cash taxes[b]	(71)	(90)	19	-21%
Sustaining capital expenditures[c]	(716)	(688)	(28)	4%
KML NCI DCF adjustments[d]	-	(60)	60	-100%
Other items[e]	(6)	29	(35)	-121%
DCF	**$ 5,099**	**$ 4,993**	**$ 106**	**2%**
Weighted average common shares outstanding for dividends[f]	2,279	2,276	3	0%
DCF per common share	$ 2.24	$ 2.19	$ 0.05	2%
Expected/Declared dividend per common share	$ 1.25	$ 1.00	$ 0.25	25%
Excess DCF above declared dividend	**$ 2,250**	**$ 2,717**	**$ (466)**	**-17%**

25% increase in dividend while maintaining healthy dividend coverage

Note: See Non-GAAP Financial Measures and Reconciliations.

a) Amounts are adjusted for Certain Items.

b) Includes KMI share of unconsolidated C corp JVs' cash taxes of $68 million and $61 million in 2020 and 2019, respectively.

c) Includes JV sustaining capex, $128 million and $114 million in 2020 and 2019, respectively. Excludes the noncontrolling interests' portion of KML sustaining capital expenditures in 2019.

d) The combined net income, DD&A and income tax expense adjusted for Certain Items, as applicable, attributable to KML NCI in 2019.

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

f) Includes 14 million and 13 million average unvested restricted shares that contain rights to dividends in 2020 and 2019, respectively.

2020B Adjusted Earnings

in millions, except per share

	2020 Budget	2019 Actual	Change $	Change %
DCF	**$ 5,099**	**$ 4,993**	**$ 106**	**2%**
Cash taxes[a]	71	90	(19)	-21%
Sustaining capital expenditures[b]	716	688	28	4%
Income tax expense for DCF[c,d]	(745)	(714)	(31)	4%
DD&A and amortization of excess cost of equity investments for DCF[e]	(2,844)	(2,867)	23	-1%
Other items[f]	6	(29)	35	-121%
Adjusted Earnings[c]	**$ 2,303**	**$ 2,161**	**$ 142**	**7%**
Weighted average common shares outstanding for dividends[g]	2,279	2,276	3	0%
Adjusted EPS	$ 1.01	$ 0.95	$ 0.06	6%

Note: See Non-GAAP Financial Measures and Reconciliations.

a) Includes KMI share of unconsolidated C corp JVs' cash taxes of $68 million and $61 million in 2020 and 2019, respectively.

b) Includes JV sustaining capex, $128 million and $114 million in 2020 and 2019, respectively. Excludes the noncontrolling interests' portion of KML sustaining capital expenditures in 2019.

c) Amounts are adjusted for Certain Items.

d) Includes KMI share of unconsolidated C corp JVs' book taxes, net of the noncontrolling interests' portion of KML book taxes of $79 million and $87 million in 2020 and 2019, respectively.

e) Includes KMI's share of DD&A from JVs, net of DD&A attributable to KML NCI, of $385 million and $374 million in 2020 and 2019, respectively.

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

g) Includes 14 million and 13 million average unvested restricted shares that contain rights to dividends in 2020 and 2019, respectively.

2020B Capital Expenditures

$ in millions

Sustaining Capital	2020 Budget	2019 Actual	Change
Natural Gas Pipelines[(a)]	$ 363	$ 339	$ 24
Products Pipelines[(a)]	81	87	(6)
Terminals[(a)]	230	222	8
CO_2	16	17	(1)
Corporate / other	26	23	3
Total sustaining capital expenditures[(b)]	**$ 716**	**$ 688**	**$ 28**

Discretionary Capital	2020 Budget	2019 Actual	Change
Natural Gas Pipelines[(c)]	$ 1,676	$ 2,234	$ (558)
Products Pipelines	151	94	57
Terminals	244	97	147
CO_2 - Source & Transport	60	35	25
CO_2 - Oil & Gas	263	293	(30)
Corporate/Other	1	-	1
Total discretionary capital	**$ 2,395**	**$ 2,753**	**$ (358)**

Positive market fundamentals resulting in expansion & new build opportunities across our segments, particularly in our Natural Gas segment

Note: Before Certain Items.

a) 2019 includes KMI share of KML sustaining capital expenditures.

b) Includes KMI share of unconsolidated JVs' sustaining capital expenditures of $128 million and $114 million in 2020 and 2019, respectively.

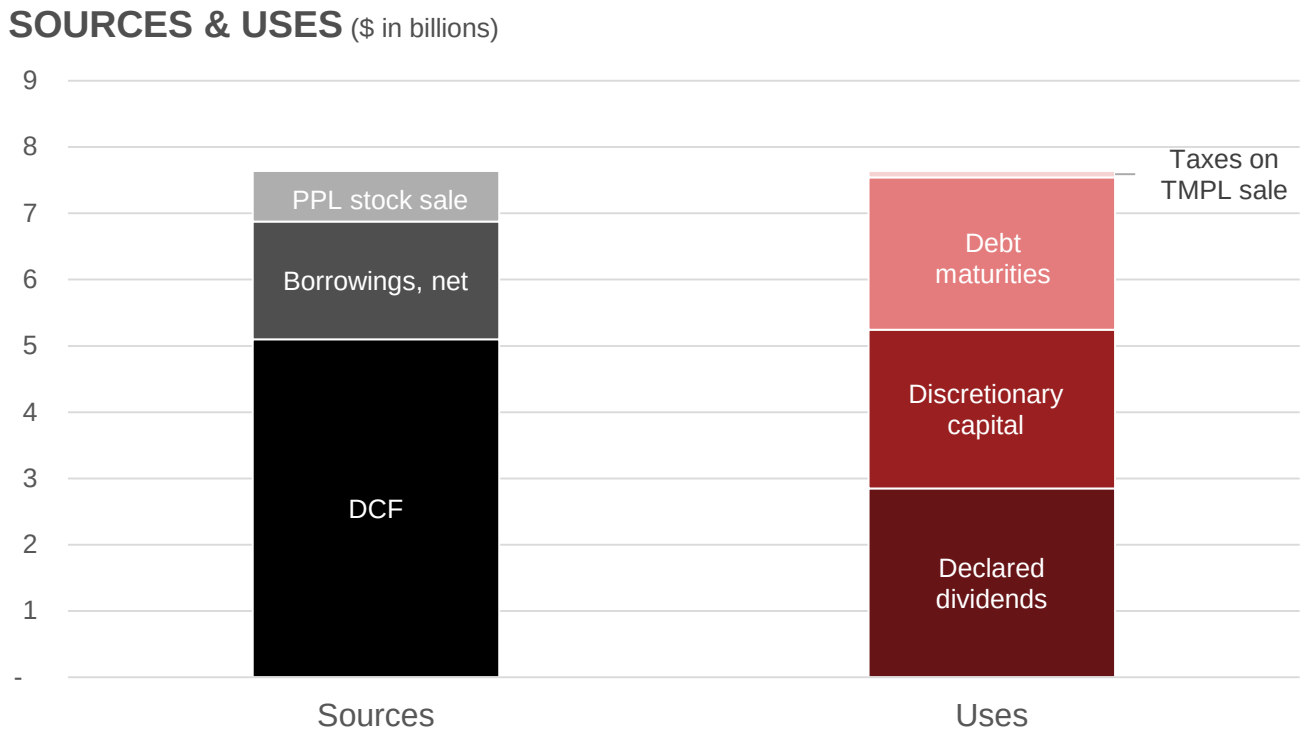
c) 2020 budget includes $379 million JV expansion spending, net of partner contributions for consolidated JVs, and $119 million JV debt maturities.

2020B Sources & Uses

$ in millions

Sources	2020 Budget
DCF	$ 5,099
Revolver Borrowing/Debt Issuances[(a)]	1,778
After-tax proceeds from Pembina stock sale	764
Total sources	**$ 7,641**

Uses	2020 Budget
Expected dividends declared	$ 2,849
Discretionary Capital	2,395
Cash taxes remaining for TransMountain sale	99
Debt maturities	2,298
Total uses[(a)]	**$ 7,641**



Plan to use internally generated cash flow to fully fund dividend payment & almost all discretionary spending

Proceeds from sale of Pembina stock used to pay down debt

No need to access equity markets

Note: See Non-GAAP Financial Measures and Reconciliations.

a) Excludes certain changes in working capital, potential rate case refunds, and will vary depending on use of discretionary free cash flow.

Leverage & Liquidity[a]

$ in millions

	2020 Budget
Net Debt (Year End)	$ 32,964
Adjusted EBITDA	$ 7,582
Net Debt[b] to Adjusted EBITDA	**4.3x**

Financial flexibility with ~$4 billion of capacity on our credit facility & manageable future debt maturities

KMI revolver capacity	**12/31/2019**
Committed revolving credit facility[c]	$ 4,000
CP / Revolver borrowing	(37)
Letters of credit	(84)
Available capacity	**$ 3,879**

KMI long-term debt maturities[d]	
2020	$ 2,298
2021	2,416
2022	2,466
2023	3,243
2024	1,919

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) KMI corporate revolver facility has a November 2023 maturity.

d) 5-year maturity schedule of KMI's consolidated long-term debt, excluding fair value adjustments, $110 million preferred securities, $44 million non-cash foreign exchange impact on Euro denominated debt, and immaterial capital lease obligations.

2020B Quarterly Profile

$ in millions, except per share

Adjusted Segment EBDA	Q1	Q2	Q3	Q4	Total
2020 Budget	26%	24%	24%	26%	$ 7,775
2019 Actual	26%	24%	24%	26%	$ 7,749
Adjusted EBITDA					
2020 Budget	26%	24%	24%	26%	$ 7,582
2019 Actual	26%	24%	24%	26%	$ 7,618
Distributable Cash Flow (DCF)					
2020 Budget	28%	22%	23%	27%	$ 5,099
2019 Actual	27%	23%	23%	27%	$ 4,993
Adjusted EPS					
2020 Budget	27%	23%	23%	27%	$ 1.01
2019 Actual	27%	23%	23%	27%	$ 0.95

Note: See Non-GAAP Financial Measures and Reconciliations.

2020B Cash Tax Calculation Detail

$ in millions

	2020 Budget
Adjusted Segment EBDA	7,775
Net income attributable to NCI	(67)
JV earnings from C corps	(325)
JV distributions from C corps (net of 65% dividend received deduction)	88
JV book DD&A (pass-through entities)	142
General and administrative and corporate charges	(590)
Interest, net	(1,690)
Book capex items expensed for tax purposes	(616)
Tax DD&A	(5,808)
Other items	21
Taxable loss	**$ (1,070)**

KMI U.S. federal cash taxes	$ -
Other cash taxes[(a)]	71
Total cash taxes	**$ 71**

Do not expect KMI to pay meaningful U.S. federal cash taxes until beyond 2026

Note: All items shown before certain items. See Non-GAAP Financial Measures and Reconciliations.

a) Includes cash taxes for our share of unconsolidated C corp JVs (Citrus, Plantation and NGPL), Texas margin tax and other state income taxes.

2020 Budget Sensitivities

Limited overall commodity exposure

2020B assumptions	Change	2020B DCF impact (full year)			
		CO_2	Natural Gas	Products	Total company
$55/bbl WTI	$1/bbl WTI	$0.8 million NGL $0.6 million CO_2 $1.3 million crude *$2.7 million total*	$0.8 million	$1.2 million	~$5 million
$2.50/mmbtu	$0.10/mmbtu		$1.2 million		~$1 million
NGL/crude ratio: 37% in CO_2 segment 60% in Natural Gas segment	1% NGL/crude oil ratio	$1.8 million	$0.5 million		~$2 million
3mo LIBOR average of 1.64%	100-bp change in LIBOR				~$89 million[(a)]
See CO_2 segment slides for production assumptions	500 bopd in SACROC, Katz, Goldsmith, or Tall Cotton	$8.1 million			
	500 bopd in Yates	$4.2 million			
	50 mmcfd in CO_2	$7.6 million			

Note: See Non-GAAP Financial Measures & Reconciliations.

a) Interest expense impact. As of YE 2019 $8.9 billion, or 27%, of KMI's long-term debt was floating rate.

KMI: Then & Now

Celebrating our 20th investor day

Key metrics	2001 Investor Day	2020 Investor Day	Increase
Market capitalization	$6 billion	$49 billion	Over 700%
Enterprise value	$9 billion	$84 billion	Over 800%
Miles of pipeline	~33,000	~83,000	~150%
# of employees	~3,800	~11,900	Over 200%
Net income (last actual)	~$150 million	~$2.2 billion	More than 13x
CEO salary	$1	$1	None

A lot of things have changed, but management remains aligned with shareholders

Natural Gas

Segment Presentation

Natural Gas Segment Overview

Connecting key natural gas resources with major demand centers

Asset Summary

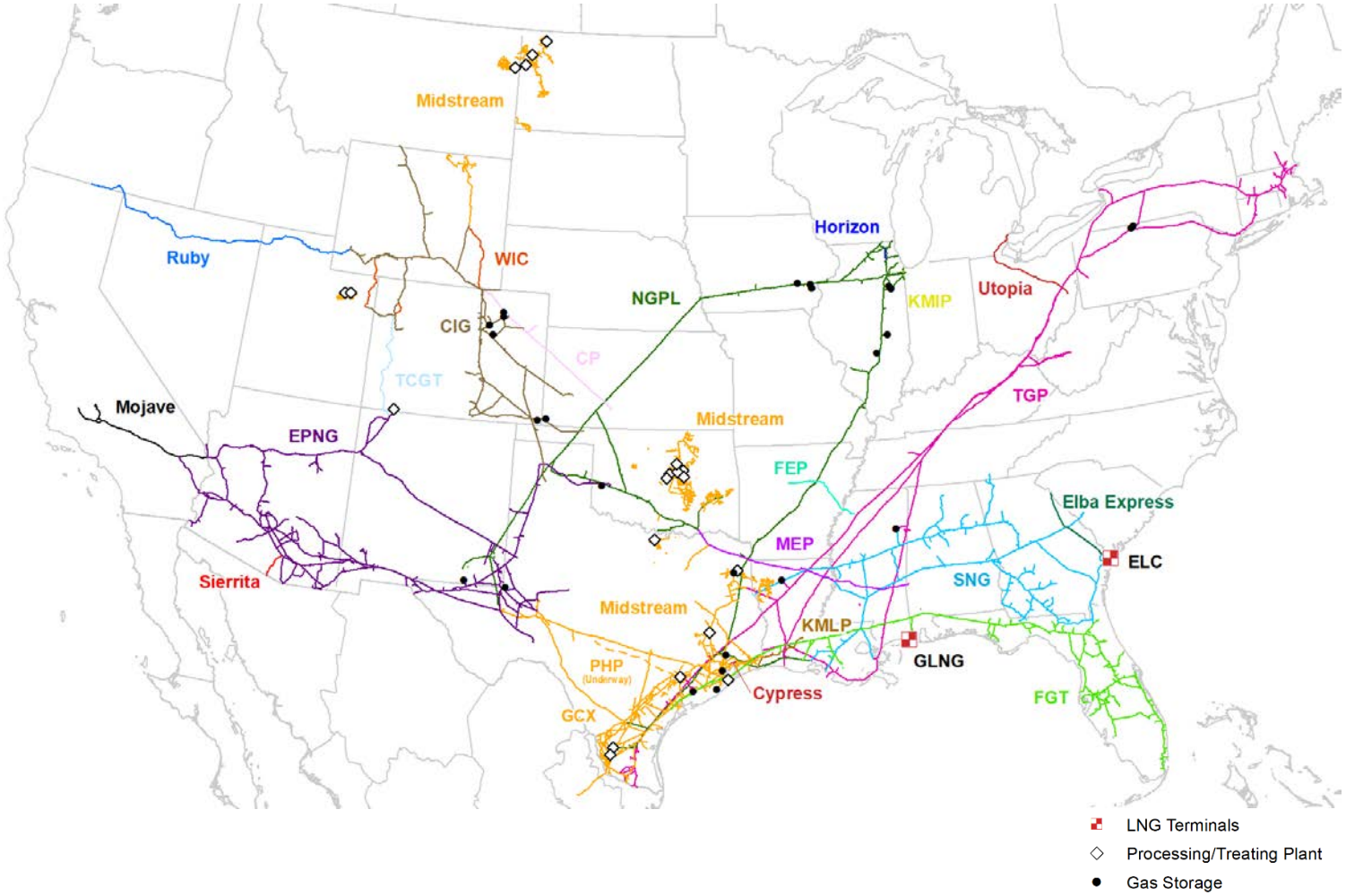
Natural gas pipelines:	~70,000	miles
NGL pipelines:	~1,200	miles
Natural gas transported (U.S. consumption & exports)		~40%
Working gas storage capacity:	659	bcf

2020B EBDA[a]: $4.7 billion

Project Backlog:

$2.4 billion to be completed in 2020-2022[b]

- Permian takeaway, including de-bottlenecking & new build (PHP)
- Transport projects supporting LNG exports
- LNG liquefaction (Elba remaining units)
- Supply for U.S. power & LDC demand
- Bakken G&P expansions
- Exports to Mexico



a) 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
b) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

Long-Term Growth Drivers: Natural Gas Segment

Capitalizing on industry trends

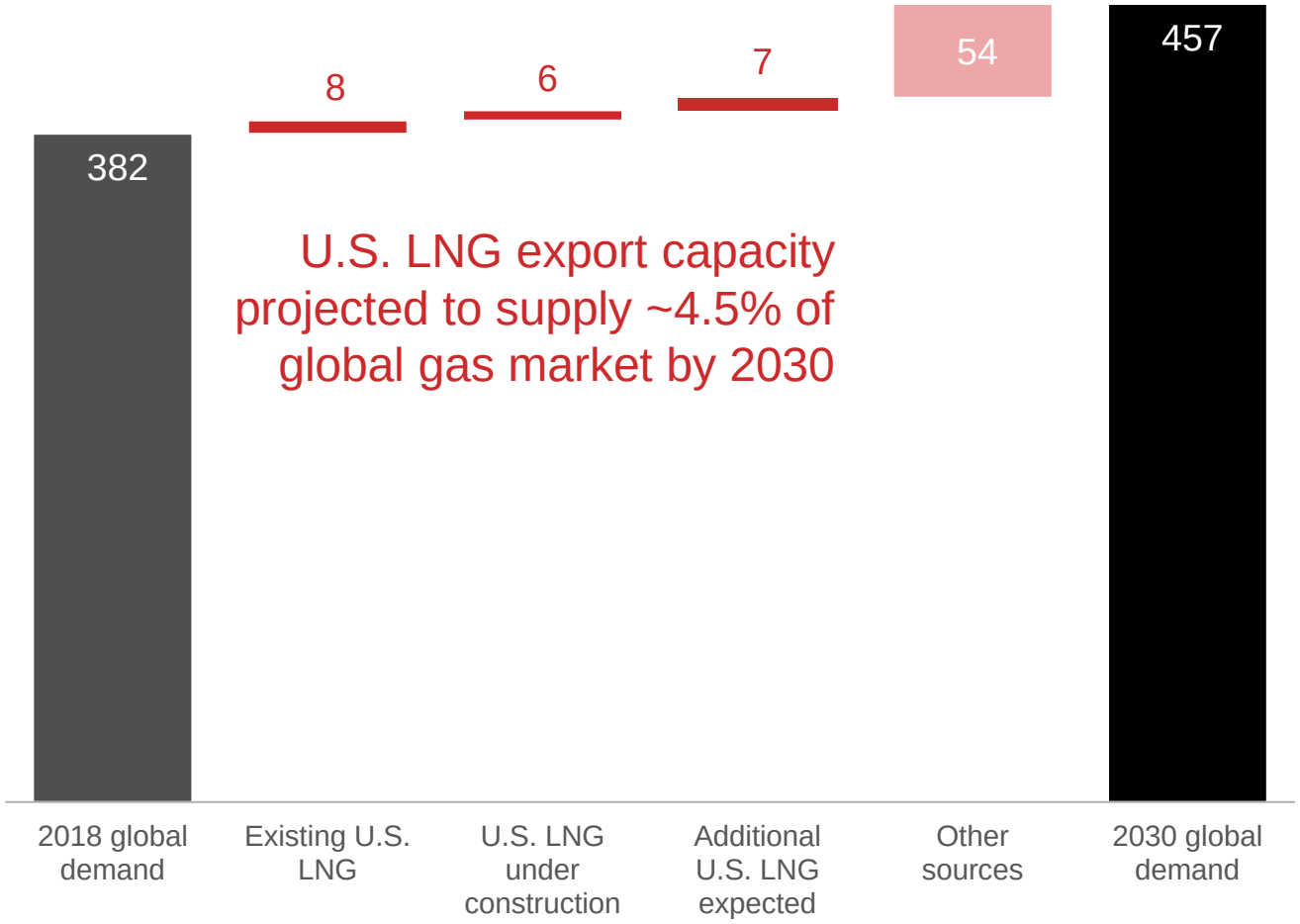
Exports	▪ LNG exports: pipeline infrastructure & liquefaction facilities ▪ Exports to Mexico: additional volume with ramp up of in-country infrastructure ▪ Outlets for growing Permian supply from GCX & PHP
Shale-driven expansions / extensions to serve associated & dry gas growth	▪ Leveraging off of existing footprint (Permian, Bakken) ▪ Greenfield projects
Storage & linepack support for increasingly variable demand	▪ LNG export interruptions (e.g., due to weather, maintenance) ▪ Complement variable renewable generation with responsive gas deliverability ▪ Support daily & seasonal variability in exports to Mexico ▪ Meet peak demand periods in summer & winter
Gulf Coast petrochemical & other industrial demand	▪ Strategic pipeline footprint & storage to serve growing demand ▪ Established deliverability into major markets
Pipeline conversions & reversals	▪ Repurpose assets to maximize value of pipe in the ground ▪ Brownfield solutions in increasingly challenging market for new construction
Operating leverage	▪ Capture price volatility & deliverability needs with storage / linepack ▪ Tailor premium services to leverage operational flexibility
End-user / LDC demand growth	▪ Regional power generation opportunities, baseload growth & peaking ▪ Unique last-mile connectivity to LDC markets

U.S. LNG Exports are Growing

Expected to more than triple by 2025

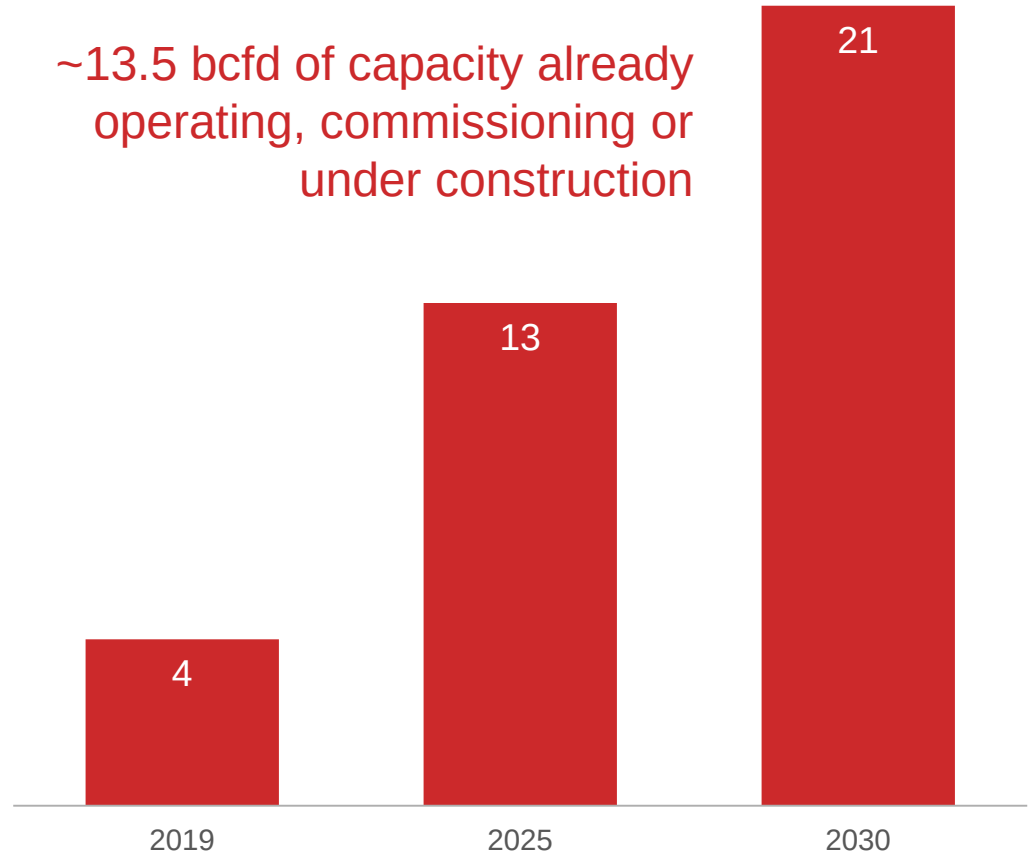
GLOBAL NATURAL GAS DEMAND

bcfd



PROJECTED U.S. LNG EXPORTS

bcfd



Source: International Energy Agency, World Energy Outlook 2019 (global natural gas demand, declines at existing liquefaction facilities), U.S. EIA (U.S. liquefaction capacity), WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2019 (projected U.S. LNG exports)

Supporting the Buildout of U.S. LNG Exports

Serving significant liquefaction capacity & well-positioned to capture more

Kinder Morgan network advantages:

Natural gas transportation leader

~70,000 miles of natural gas pipelines
Move ~40% of U.S. natural gas consumption & exports

Supply diversity

Connected to every important U.S. natural gas resource play

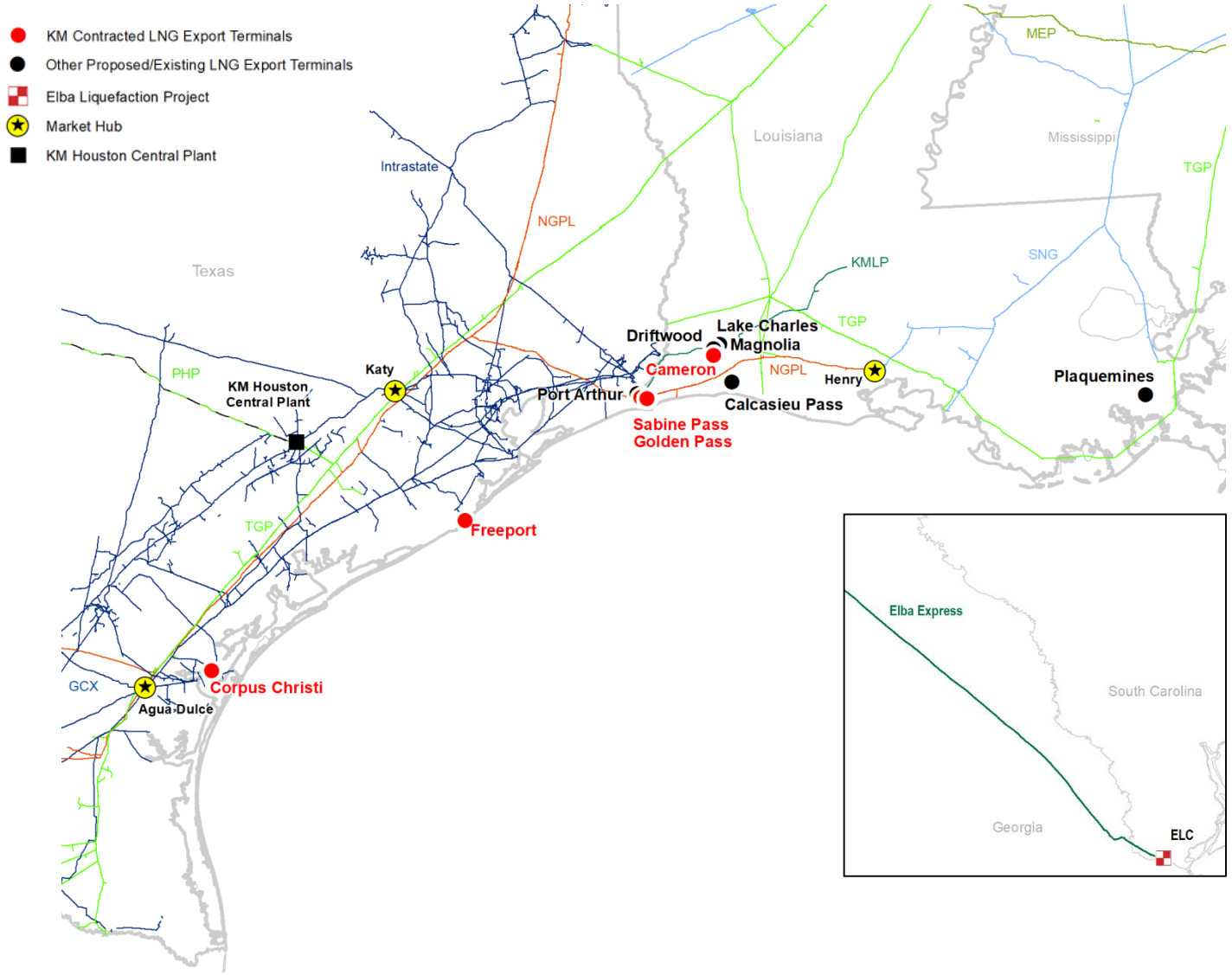
Premier deliverability

659 bcf of working gas storage in production & market areas

Transporter of choice

Contracted capacity online	Contracted capacity FID / to come	Average remaining contract term	In active discussions
~3.5 bcfd	~2.5 bcfd	~17 years	~2-4+ bcfd

Also deliver ~1 bcfd of producer / marketer supply



Project Highlight: Elba Island LNG Export Terminal

Elba Liquefaction Company (ELC)[a] / Southern LNG Company (SLNG)

Project Scope

- Liquefaction facilities (10 small-scale modular units)
- Ship loading facilities; boil-off gas compression
- Located on Elba Island near Savannah, Georgia

Project Statistics

- Liquefaction Capacity: 2.5 mtpa or ~350 mmcfd
- Capital (100%):
  - ELC: ~$1,420 million[b] / ~$770 million KM share
  - SLNG: ~$460 million
- In-service: Q3 2019 through Q2 2020 (phased)
- Contract term: 20 years

Current Status

- FERC certificate issued June 2016
- DOE FTA & non-FTA authorizations received
- Four units now online
- Construction & startup ongoing with ramp-up activities on fifth unit underway

Fully-contracted under 20-year take-or-pay agreement with Shell
First four units now in service generate 88% of KM project revenue

a) ELC is a 51 / 49 joint venture of Kinder Morgan & investment funds managed by EIG Global Energy Partners (EIG).
b) Excludes non-KM capitalized interest cost.

Key Market: Exports to Mexico

Expect to maintain market share of growing Mexico market | ~55%[a] in 2019

Extensive footprint offers diverse supply options to multiple Mexico interconnections

- Including 12 direct & 4 indirect

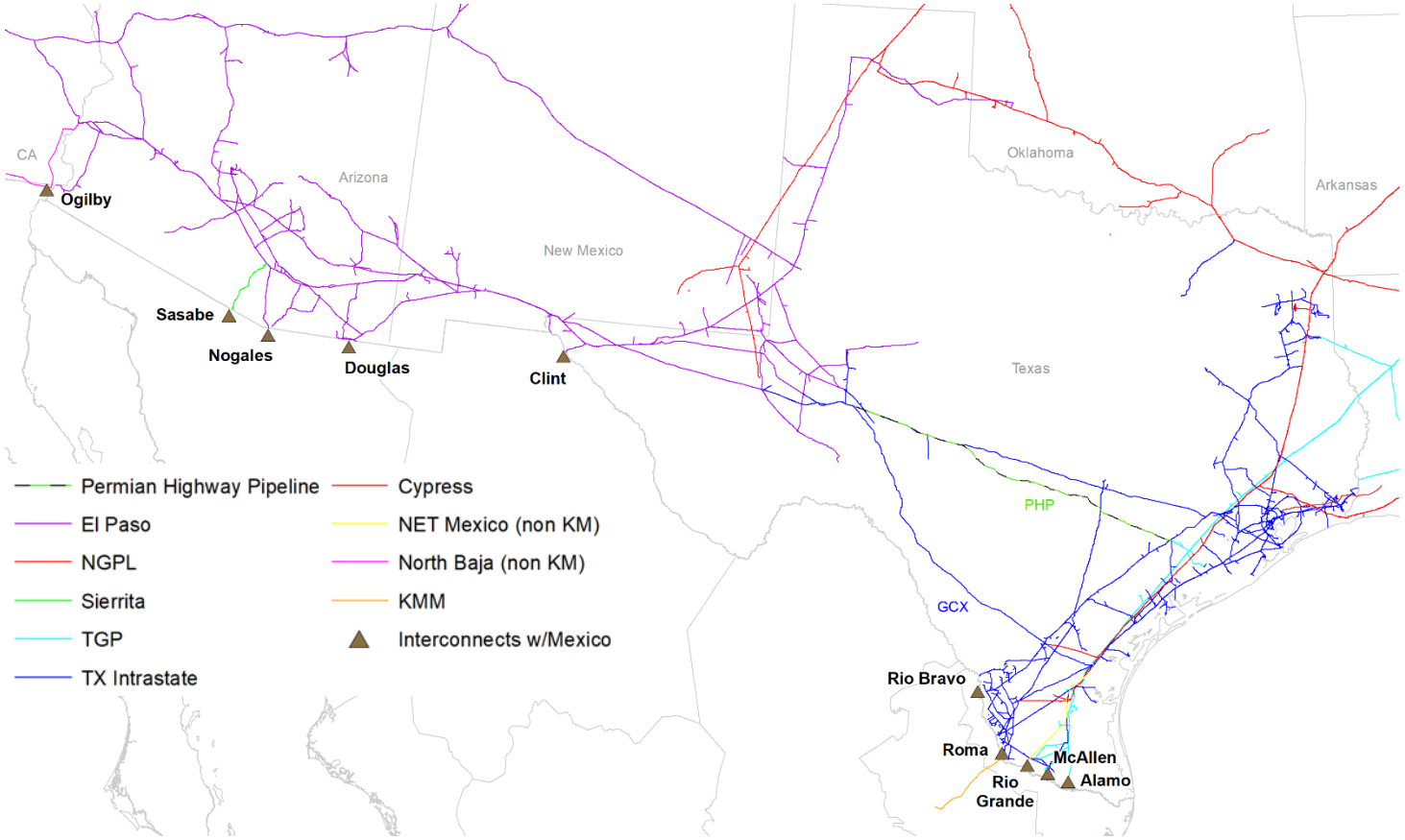
U.S. natural gas exports to Mexico are expected to grow by 33% – or ~1.7 bcfd – to 6.7 bcfd by 2024[b]

~1 bcfd of capacity put in service for ~$0.4bn since 2014 & another $0.2bn in backlog for ~0.6 bcfd

Opportunities remain:

- Expansions of existing assets (including TGP & Monterrey)
- U.S. greenfield infrastructure (such as PHP)
- Storage & hub services near the border

2019 volumes delivered	Contracted capacity	Average remaining contract term	New capacity underway
~3.1 bcfd	~3.5 bcfd	~11 years	~0.6 bcfd



Multiple pipelines across our network supply growing Mexican demand with attractive opportunities in the future

Note: KM Projects / Long-Term Commitments to Mexico detail available in Natural Gas Pipelines Segment Presentation.

a) Sources: U.S. Energy Information Administration - U.S. Natural Gas Exports, Velocity Suite – pipeline nomination data, Nueva Era Pipeline Informational Postings, Sur de Texas-Tuxpan Pipeline Informational Postings & KM Analysis.

b) Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2019.

Leading the Way Out of the Permian

Successfully completed GCX on time & budget | PHP well underway

Leveraging existing footprint into new takeaway capacity that reaches across Texas & the Desert/Southwest (DSW), connecting into major demand markets

- Our advantaged network offers broad end-market optionality with deliverability to Houston markets (power, petrochemical), substantial LNG export capacity & Mexico

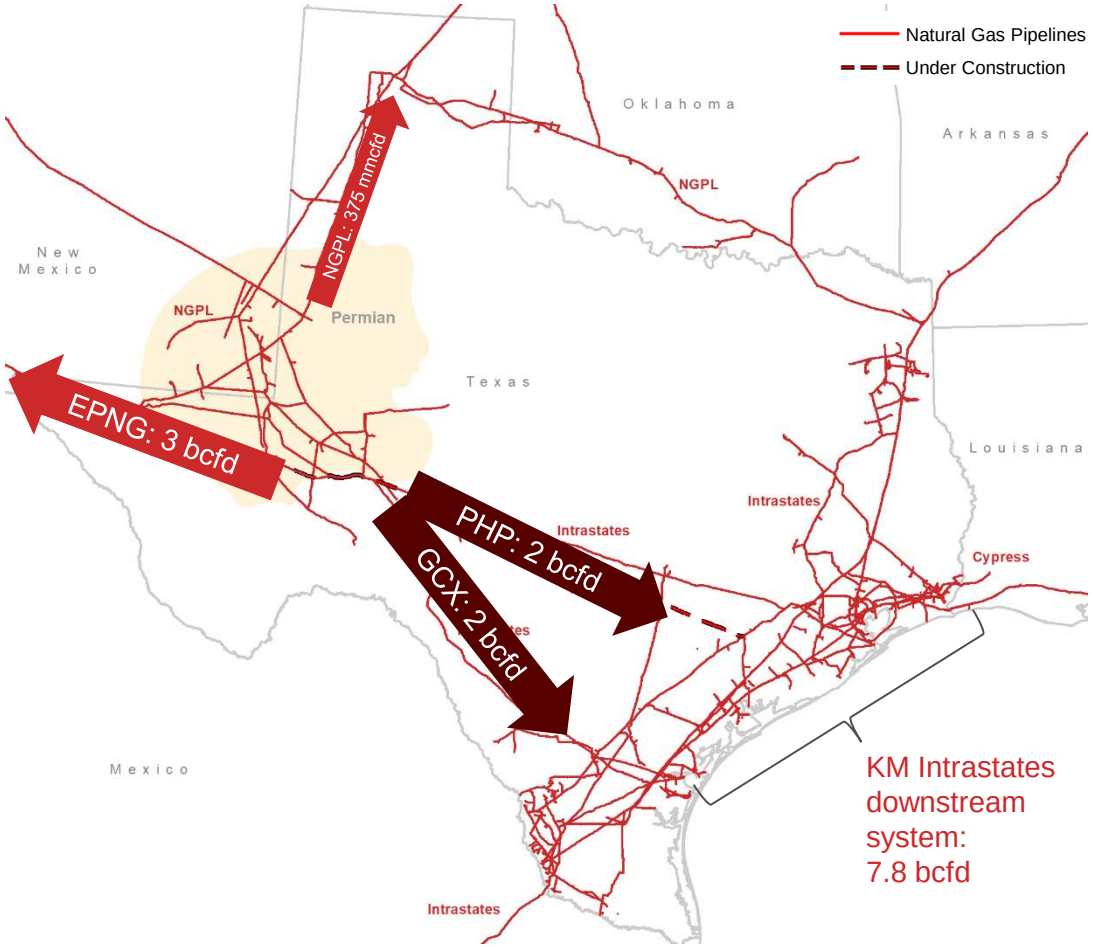
Investing more than $325 million to increase capacity & improve connectivity across existing Texas Intrastates pipeline networks by 1.7 bcfd

- Key to unlocking millions of barrels of additional oil production from the Permian Basin & billions of dollars of value
- Enhances deliverability of E. Texas natural gas supply into Houston area markets

In customer discussions about a third KMI pipeline (Permian Pass Pipeline)

- Targeting E. Texas intrastate markets & LNG terminals in E. Texas & Louisiana
- In-service date beyond 2022

	Gulf Coast Express (GCX)	Permian Highway Pipeline (PHP)
Mainline:	450 miles of 42” pipeline	~430 miles of 42” pipeline
Endpoint:	Near Agua Dulce	Near Katy
KM ownership:	34%	26.7%
Capacity:	2.0 bcfd	2.1 bcfd
Capital (100%):	$1.75 billion	$2.15 billion
In-Service:	Operating since Sept. 2019	Early 2021
Min. contract term:	10 years	10 years



Providing unparalleled takeaway capacity from the Permian basin to the Gulf Coast & DSW markets

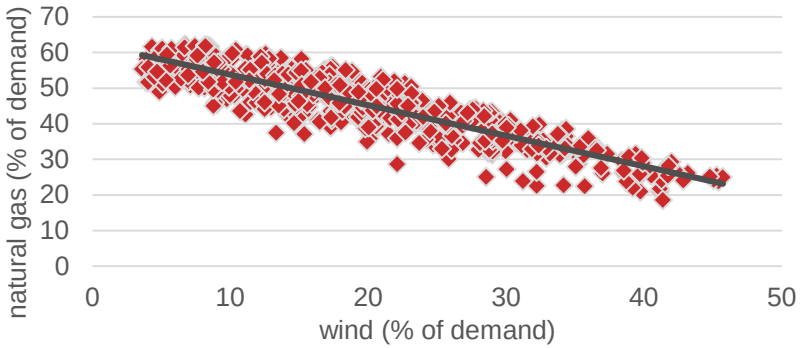
Growth Driver: Supporting Increasing Variable Demand

Opportunities for increased throughput, short notice high deliverability services & gas storage

Market dynamics & KM response	
Renewable generation	■ Natural gas-fired generation ramps during periods of low availability from wind & solar ■ Necessary to provide variable amounts of gas pipeline capacity on-demand or with limited notice ■ Increases necessity of pipeline linepack & market area storage ■ Tailor services to provide required deliverability, including allocating capacity to provide additional no notice or hourly services
Export demand	■ Significant export-related demand fluctuations as infrastructure ramps ■ Interruptions to LNG exports due to weather or other outages[b] ■ Minimal existing storage capability in Mexico ■ Provide responsive pipeline & storage services with our multiple large diameter pipelines & 659 bcf of working gas storage in production & market areas
Northeast supply constraints	■ Continued reliance on higher-carbon fuels including fuel oil, Russian LNG & coal to meet winter demand due to insufficient gas pipeline capacity to the market ■ More than 4,500 MW of gas fired generation in ISONE at risk when pipelines are constrained[c] ■ Abundant natural gas supply available in nearby markets ■ Expansions & extensions to provide last-mile connectivity

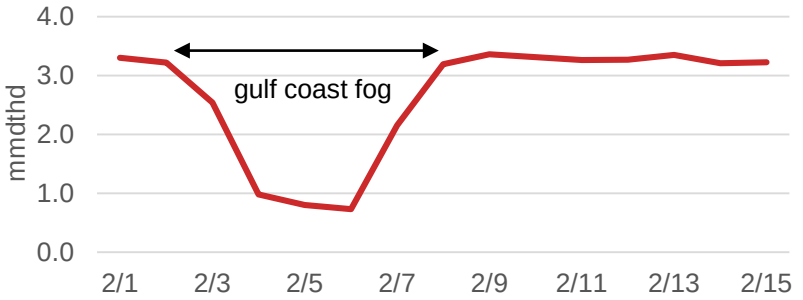
PERCENTAGE LOAD FACTOR GAS VS. WIND[a]

daily ERCOT generation (July 2018-December 2019)



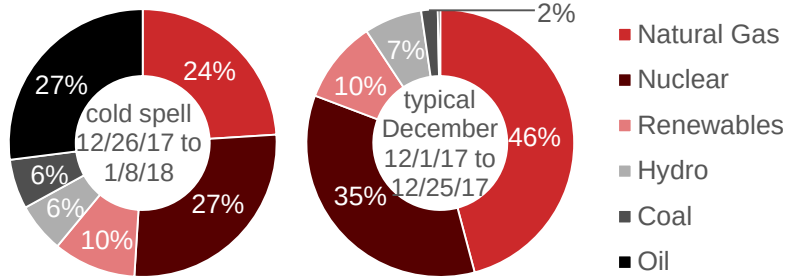
TOTAL SABINE PASS DELIVERIES[b]

Feb 1-15, 2019



NEW ENGLAND RELIANCE ON NON-GAS[c]

periods of extreme cold, winter 2017/18



a) U.S. Energy Information Administration – U.S. Electric System Operating Data
b) Velocity Suite/KM Data
c) ISO New England 2019/2020 winter outlook

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
100% KMI-owned:								
TGP	Tennessee Gas Pipeline	100%	11,800	12.1	80	8.8 / 3.9[a]	NA	10/31/2022
EPNG	El Paso Natural Gas + Mojave	100%	10,670	6.4	44	5.7	NA	12/31/2021
CIG	Colorado Interstate Gas	100%	4,300	6.0	38	5.6 / 5.6[a]	4/1/2022	9/30/2020
WIC	Wyoming Interstate	100%	850	3.6	–	3.5	4/1/2022	12/31/2020
KMLP	Kinder Morgan Louisiana Pipeline	100%	135	3.0	–	13.9	NA	NA
CP	Cheyenne Plains	100%	410	1.2	–	1.6	NA	NA
TCGT	TransColorado	100%	310	0.8	–	0.6	NA	NA
EEC	Elba Express	100%	200	1.1	–	17.5	NA	NA
Jointly-owned (asset stats shown at 100%):								
NGPL	Natural Gas Pipeline Co. of America	50%	9,100	7.6	288	5.3 / 3.6[a]	NA	6/30/2022
SNG	Southern Natural Gas	50%	6,930	4.4	66	5.3 / 1.8[a]	9/1/2024	8/31/2021
FGT	Florida Gas Transmission	50%	5,360	3.9	–	9.8	2/1/2021	1/31/2021
FEP	Fayetteville Express	50%	185	2.0	–	1.2	NA	NA
MEP	Midcontinent Express	50%	510	1.8	–	1.4	NA	NA
	Ruby	50%[b]	680	1.5	–	3.3	NA	NA
	Sierrita	35%	60	0.2	–	19.8	NA	NA
Storage & LNG (asset stats shown at 100%):								
	Keystone Gas Storage	100%	15	0.4	6	2.4	NA	
SLNG	Southern LNG Co. (Elba Island)	100%	–	1.8	12	12.8	NA	
GLNG	Gulf LNG	50%	5	1.5	7	11.8	NA	
ELC	Elba Liquefaction Company	51%	–	0.14[c]	–	20	NA	
YGS	Young Gas Storage (CIG)	47.5%			6	5.4	NA	

a) Transport / Storage.
b) Reflects third party ownership of a 50% preferred interest.
c) 4 of 10 units in service (total capacity 0.35 bcfd).

Natural Gas: Intrastate, G&P and NGL Assets

Key statistics

	Ownership	Miles	Capacity (bcfd)	Avg. Remaining Contract Term (yrs)	Storage (bcf)	Treating (GPM)	Processing (bcfd)
100% KMI-owned natural gas pipelines:							
KMTP / Tejas	100%	5,850	7.8	6.0	132	1,680	0.5
Copano – gas	100%	6,620	4.8	2.7		4,100	1.2
KinderHawk Gathering	100%	520	2.4	Life of Lease		2,960	
Mier-Monterrey	100%	90	0.7	8.1			
North Texas Pipeline	100%	80	0.3	13.6			
Hiland (Williston Basin) – gas	100%	2,070	0.6	14.9		80	0.3
Camino Real Gathering – gas	100%	70	0.2	2.8			
Altamont Gathering	100%	1,460	0.1	2.5			0.1
Jointly-owned natural gas pipelines (asset stats shown at 100%):							
Eagle Hawk Gathering – gas	25%	530	1.2	Life of Lease			
Gulf Coast Express	34%	520	2.0	9.7			
Red Cedar Gathering	49%	900	0.3	4.5		4,600	
Treating - Leased Units	100%	Plants in service: 50 Amine / 59 Mechanical Refrigeration Units / 19 Dew Point					

	Ownership	Miles	Capacity (mbbld)	Avg. Remaining Contract Term (yrs)	Storage (mbbl)
100% KMI-owned liquids pipelines:					
Copano - liquid	100%	430	115	5.1	
Jointly-owned liquids pipelines (asset stats shown at 100%):					
Cypress (FERC Regulated)	50%	100	56	1.3	
Utopia (FERC Regulated)	50%	270	50	19.0	
Eagle Hawk Gathering- condensate	25%	400	220	Life of Lease	60

Natural Gas Segment Commodity Price Exposure

Price Δ & Commodity	2020B DCF impact[d]
$1/bbl WTI	$0.8 million
1% NGL / crude ratio[a]	$0.5 million
1¢/gal ethane frac spread[b]	$1.1 million
$0.10/Dth natural gas[c]	$1.2 million

a) Excluding ethane. Budgeted NGL / crude ratio = 60%.
b) An unfavorable impact can be limited by reducing ethane equity volumes through operational changes & contractual elections.
c) Assumes constant ethane frac spread vs. natural gas prices.
d) See Non-GAAP Financial Measures & Reconciliations.

Manageable Natural Gas Re-Contracting Exposure

Analysis of existing contracts that renew during next two years

EXPECTED ANNUAL NET RE-CONTRACTING EXPOSURE (KM SHARE):

% of $7.8bn 2020B KMI Total Segment EBDA[a]

	2021	2022
Interstate pipelines	(2.4)%	(1.6)%
Intrastates & G&P	(0.5)%	(0.6)%
Total Natural Gas Pipeline Segment[b]	(2.9)%	(2.2)%
Primary drivers / pipelines	FEP Ruby	Ruby

- Expiring contracts are assessed for volumetric & rate risk based on November 2019 market assumptions (time of budget)
- Excludes benefit of new cash flows from growth projects
- Excludes potential for re-purposing underutilized assets or otherwise enhancing service offerings
- Contracts on interstate pipelines have average remaining term of 6.6 years

Expect to more than offset re-contracting headwinds with growth projects underway, increases in usage, opportunities for currently uncontracted capacity & improved value for storage

Expect reduction in re-contracting exposure after 2022

a) 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
b) Increase in 2021 recontracting exposure from 2019 Investor Day primarily relates to decrease in KMI Segment EBDA primarily as a result of asset sales.

Projects Placed Into Service During 2019

New natural gas projects expected to generate $431 million of annual EBITDA

Asset	Project	In-service Date	Capacity (mDthd)	Capital, KM Share ($mm)	EBITDA, KM Share ($mm)
ELC	Elba Liquefaction - 3 units and ancillary facilities	Sep - Dec 2019	107	$543	
SLNG	Terminal Upgrades-Elba Island	Sep 2019	357	$460	
FGT	East / West Project	Jan/Feb 2019	275	$40	
	Various Expansions	Aug-Oct 2019	410	$7	
CIG	Discovery Midstream - NewCO / WY CO	Aug 2019	325	$14	
	Various Expansions	Apr - Dec 2019	296	$5	
TGP	Various Expansions	4Q 2019	75	$7	
EPNG	Various Expansions	Apr - Dec 2019	680	$3	
WIC	Black Hills Douglas	Oct 2019	60	$2	
SNG	Plant Miller	May 2019	5	$1	
Texas Intrastates	Gulf Coast Express	Aug 2019	2020	$616	
	TX Intrastate Crossover	Jun 2019	340	$146	
	Intrastate well / market connects	1Q 2019 - 4Q 2019	Various	$10	
	Hilcorp Old Ocean / TX City Expansion	Sep 2019	40	$9	
Gathering/ Other	Williston Basin (Hiland Gas)	Mar - Oct 2019	Various	$426	
	Altamont	Apr - Nov 2019	32	$55	
	Copano	1Q 2019 - 4Q 2019	Various	$27	
	Altamont well connects	1Q 2019 - 4Q 2019	Various	$8	
	Other	1Q 2019 - 4Q 2019	Various	$34	
Total Natural Gas Pipeline Segment:				$2,414	$431

Note: EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations. EBITDA represents first full calendar year of operation.

Project Backlog: Interstate Pipelines

Natural Gas

Asset	Project	Capital, KM Share ($mm)	Capacity (mDthd)	In-service Date	Project Status
TGP	East 300 Upgrade	$246	110	11/2022	FERC filing expected 6/2020
	Line 261 Upgrade	58	128	12/2020	FERC Certificate received 12/19/2019
EPNG	South Mainline Expansion	141	471	7/2020	FERC approval received November 2019
	Permian Expansions	81	574	1Q2020-4Q2020	Various stages of permitting and construction
	Piñon Expansion *	15	71	12/2021	Under development
ELC	Elba Liquefaction - remaining units	229	250	1/2020-6/2020	Commissioning and startup of remaining units expected through 2nd Quarter 2020
NGPL	GC Southbound Phase II (Cheniere C.C.)	114	300	1Q2020, 2Q2021	FERC 7(c) application filed 1Q 2019
	Sabine Pass Compression Expansion	34	400	11/2020	Under construction
	Lockridge Lateral Extension	26	500	4Q 2020	FERC Certificate received 10/17/2019
	NIPSCO	9	75	3Q 2020	Project execution underway
KMLP	Acadiana (Cheniere S.P.)	145	945	2Q 2022	FERC 7(c) Application filed 6/28/2019
FGT	Seminole Electric (Putnam)	48	136	6/2018, 4/2022	FERC 7(c) Application filed 5/31/2019
	Market Area/Okeechobee	5	12	1/2020	Under construction
	East Louisiana	1	75	8/2020	FERC Notice to Proceed received
Sierrita	Sierrita Gas Pipeline Expansion	18	323	4/2020	Under construction
CIG	5C Ft Lupton / High Five	2	167	6/2020	Under development
Total Interstate		$1,172	EBITDA, KM Share = $216 mm		

Note: EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations. EBITDA represents first full calendar year of operation.

Project Backlog: Intrastates and G&P

Natural Gas

Asset	Project	Capital, KM Share ($mm)	Capacity (mDthd)	In-service Date	Project Status
Texas Intrastate	Permian Highway	$600	2,100	1Q 2021	Under construction
	Intrastate Network Expansions *	326	1,675	1Q - 4Q 2020	Under construction / development
	Intrastate Network Storage Expansion	40	8 Bcf	2Q 2021	Under development
	Hilcorp Supply - Texas City Expansion	21	45	3Q 2020	Construction ongoing
	Intrastate - well / market connects *	12	Various	2020	Expansions / extensions of existing gathering systems
Gathering / Other	Williston Tier I Gas Expansion	133	200	3Q 2020	Processing plant and system gathering expansions ongoing
	Altamont - HP Slug Catcher	29	17	3Q 2020	Under development
	Other system expansion and well connects *	80	Various	2020	Expansions / extensions of existing gathering systems
Total Midstream		$1,241	EBITDA, KM Share = $222 mm		
Total Natural Gas Pipeline Segment		$2,413	EBITDA, KM Share = $438 mm		

Note: EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations. EBITDA represents first full calendar year of operation.

LNG Contract Overview

Contracted capacity (online / to come) & Elba Liquefaction

KM Asset	Contracted Capacity (mDthd)	KM Capital ($mm)	Remaining Contract Term (yrs)
TGP	1,250	$281	
KMLP	1,545	$278	
NGPL	1,975	$236	
Intrastate	740	$114	
Elba Express	436	$84	
Transport subtotal:	**5,946**	**$992**	**17**
Elba liquefaction	350 mmcfd	$1,233	**20**
Total		**$2,225**	**EBITDA = $362 mm**

~$2.2 billion of capital projects

Note: EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations. EBITDA represents first full calendar year of operation (KM share).

Products

Segment Presentation

Products Segment Overview

Strategic footprint with significant cash flow generation

Asset Summary

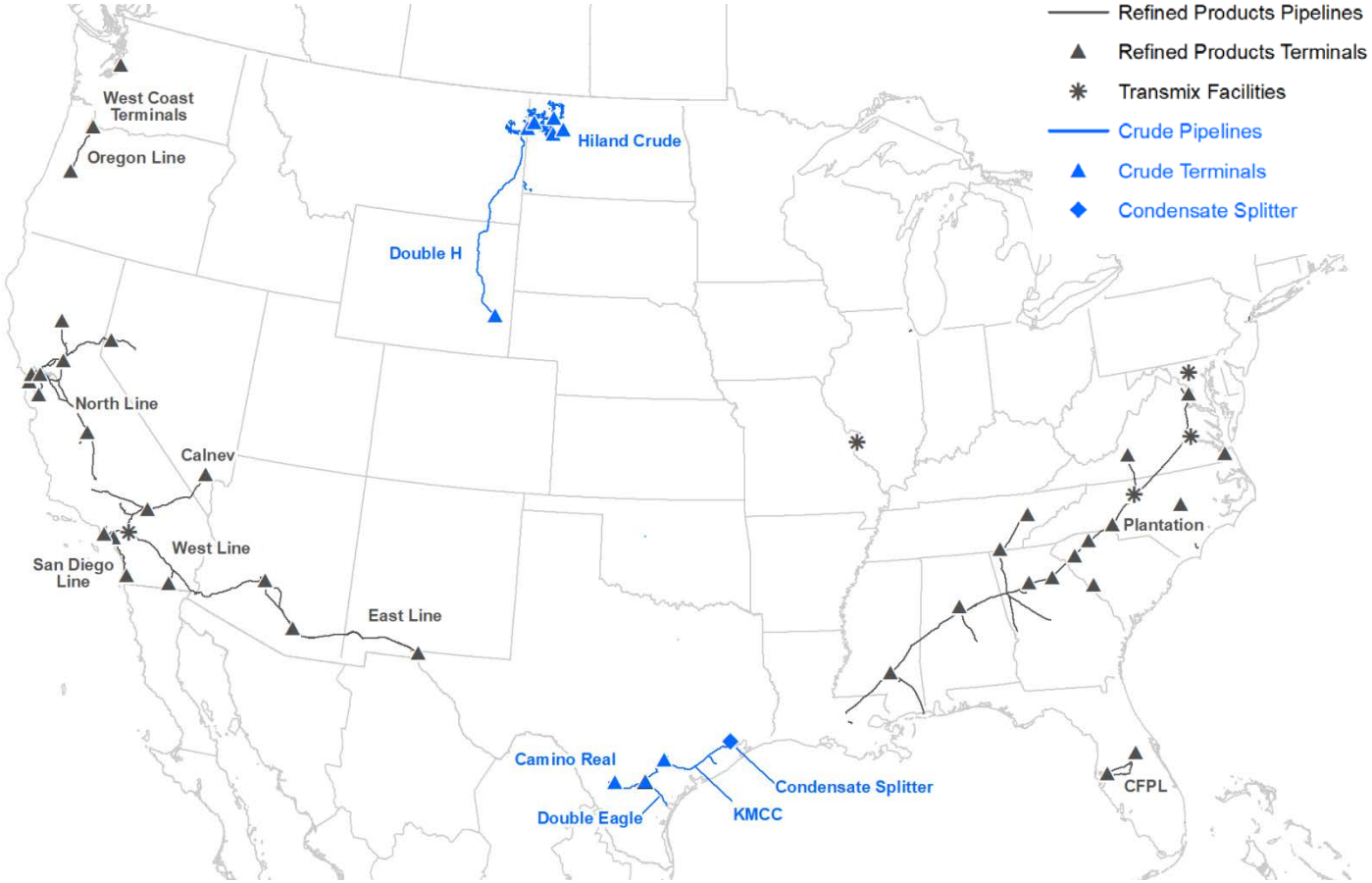
Pipelines[a]:	~9,500	miles
2019 throughput[a]	~2.4	mmbbld
Terminals:	65	terminals
Terminals tank capacity	~39	mmbbls
Pipeline tank capacity	~16	mmbbls
Condensate processing capacity	100	mbbld
Transmix	5	facilities

2020B EBDA[b]: $1.3 billion

Project Backlog:

$0.2 billion to be completed in 2020-2021[c]

- Various Bakken crude gathering projects
- Plantation Roanoke expansion
- KMCC connection with Gray Oak pipeline from Permian Basin
- Multiple refined products terminaling projects

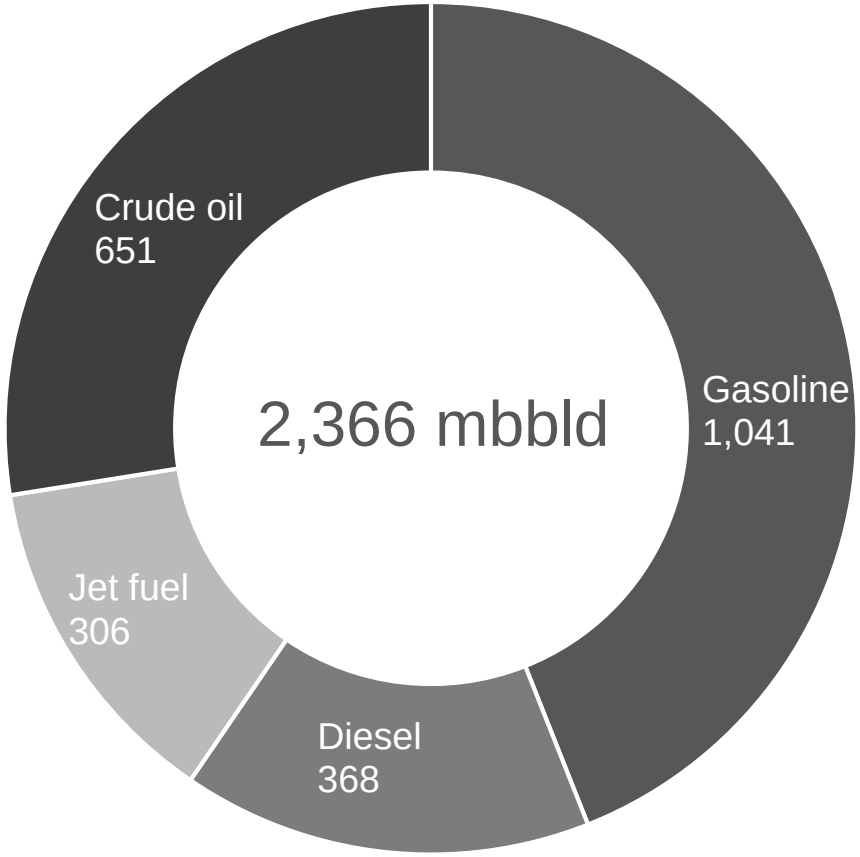


a) Volumes include SFPP, CALNEV, Central Florida, Plantation Pipe Line (KM share), KMCC, Camino Real, Double Eagle (KM share), Double H & Hiland Crude Gathering.
b) 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
c) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

Products Segment Overview

Supplying a diverse mix of feedstock & finished products critical to refining & transportation sectors

2019 DELIVERY VOLUMES[a]



Gasoline	■ Robust economy & consumer preference supports demand growth partially offset by improving fuel efficiency ■ EIA projecting 0.2% growth in 2020[b] ■ Volume by region[c]: Southeast 26% & West 74%
Diesel fuel	■ EIA projecting 0.8% growth in 2020[b] ■ Volume by region[c]: Southeast 22% & West 78%
Jet fuel	■ EIA projecting 1.2% growth in 2020[b] ■ Airports supplied include Atlanta, Las Vegas, Orlando, San Francisco & Washington D.C. ■ Volume by region[c]: Southeast 18% & West 82%
Crude oil	■ Positioned in premier basins in both Texas & N. Dakota ■ KMCC provides access to Houston refining market & export for both Eagle Ford & Permian production ■ Hiland is one of the Bakken's premier gathering systems ■ Double H provides takeaway capacity from the Bakken to Cushing via joint tariff ■ Volume by region[d]: Texas 49% & Bakken 51%

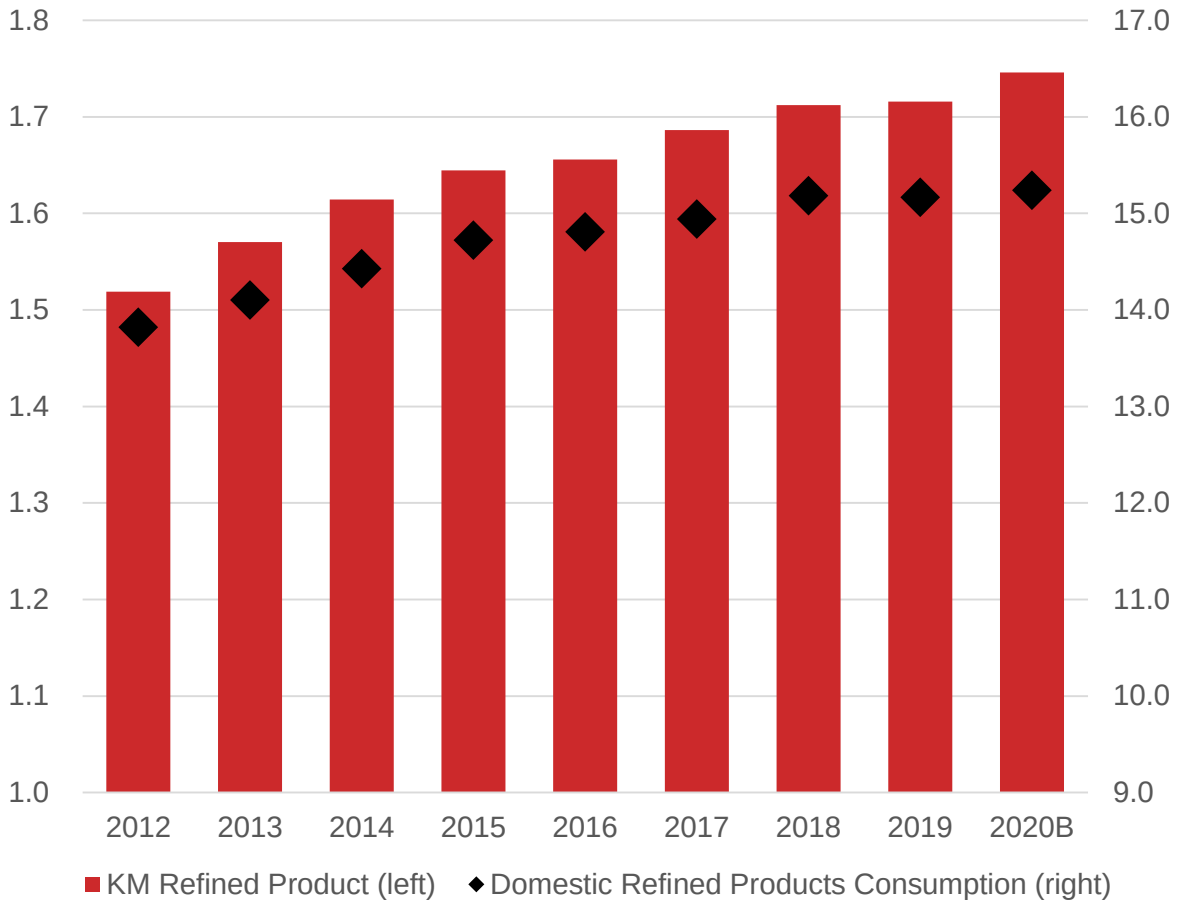
a) Kinder Morgan volumes include SFPP, CALNEV, Central Florida, Plantation Pipe Line (KM share), KMCC, Camino Real, Double Eagle (KM share), Double H & Hiland Crude Gathering; Gasoline volumes include ethanol.
b) U.S. consumption volumes per EIA, Short-term Energy Outlook Table 4a, December 2019.
c) Southeast Region Assets include Central Florida & Plantation Pipe Line (KM share); West Region includes SFPP & CALNEV.
d) Texas Crude Assets include KMCC, Camino Real, Double Eagle (KM share); Bakken Crude includes Double H & Hiland Crude Gathering.

Stable U.S. Market Demand for Refined Products

Volume growth on strategic assets consistently outpaces national average

REFINED PRODUCTS VOLUMES[(a)]

mmbbld



Unmatched connectivity between major refining centers & key demand markets

- West Coast: delivers product from major refining centers in San Francisco, Los Angeles & El Paso as well as marine terminals along west coast to cities throughout California, Arizona, Nevada, Washington & Oregon
- Southeast: Plantation Pipeline sourced by PADD 3 refineries, the most competitive refining center in the world, delivers to population centers from Mississippi to Virginia

KM CAGR of **1.7%** > U.S. consumption CAGR of **1.2%**

Note: Volume CAGR calculated from 2012 through 2020B.

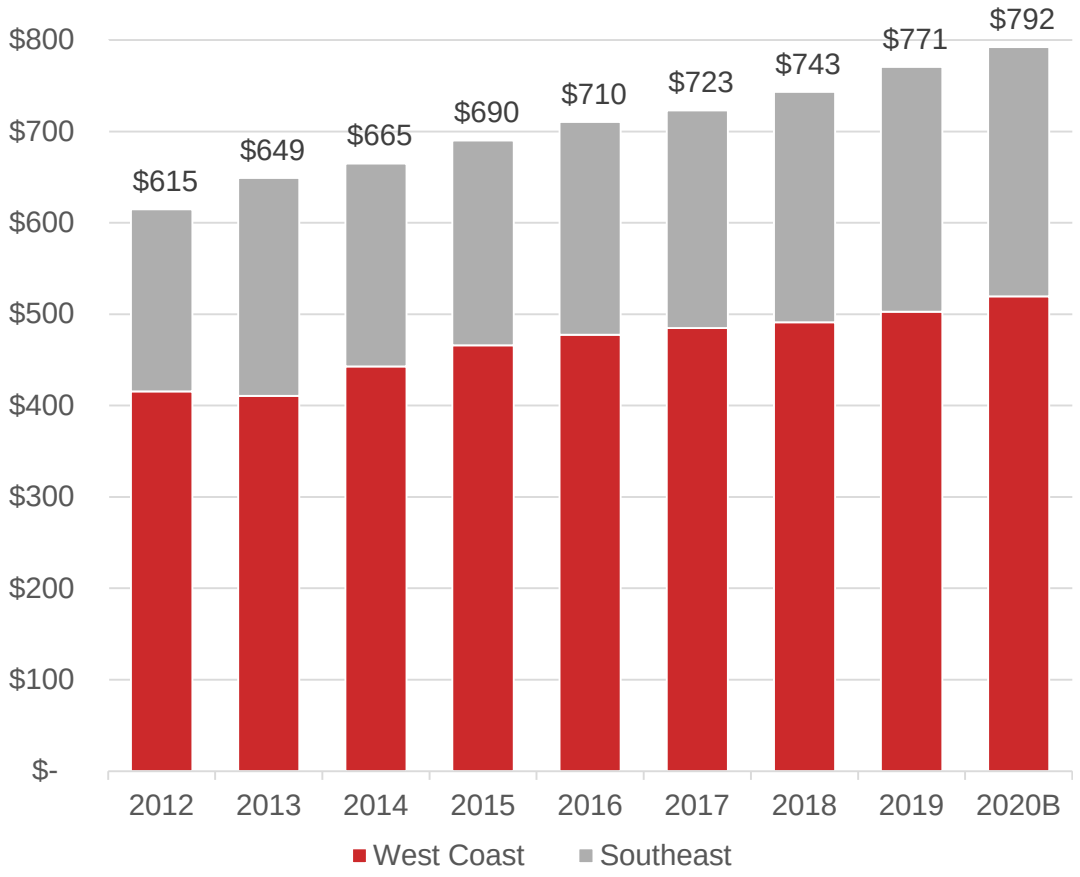
a) Kinder Morgan volumes include SFPP, CALNEV, Central Florida & Plantation Pipe Line (KM share). U.S. consumption volumes per EIA, Short-term Energy Outlook Table 4a, December 2019.

Refined Products Assets Generate Stable Cash Flows

Steadily growing volumes complemented by indexed tariff structure

REFINED PRODUCTS EBDA BY REGION[a]

$ millions



Volume growth translates to earnings growth

- Potential for market share gains in key growth areas
- Downstream terminals benefit from growth in pipeline volumes

FERC tariff indexing structure provides predictable margin growth each year

- Budgeted 1.9% index increasing effective Jul 2020[b]

KM EBDA CAGR of **3.2%** > KM VOLUME CAGR of **1.7%**

Note: See Non-GAAP Financial Measures & Reconciliations. CAGR calculated from 2012 through 2020B.

a) Adjusted Segment EBDA Includes SFPP, CALNEV, West Coast Terminals, Central Florida, Transmix, Plantation (KM share) & Southeast Terminals.

b) Internal projection of expected rate increase based on regulatory framework (PPI FG+1.23%). PPI based on U.S. Bureau of Labor Statistics Oct 2019 release.

Project Highlight: Roanoke Expansion

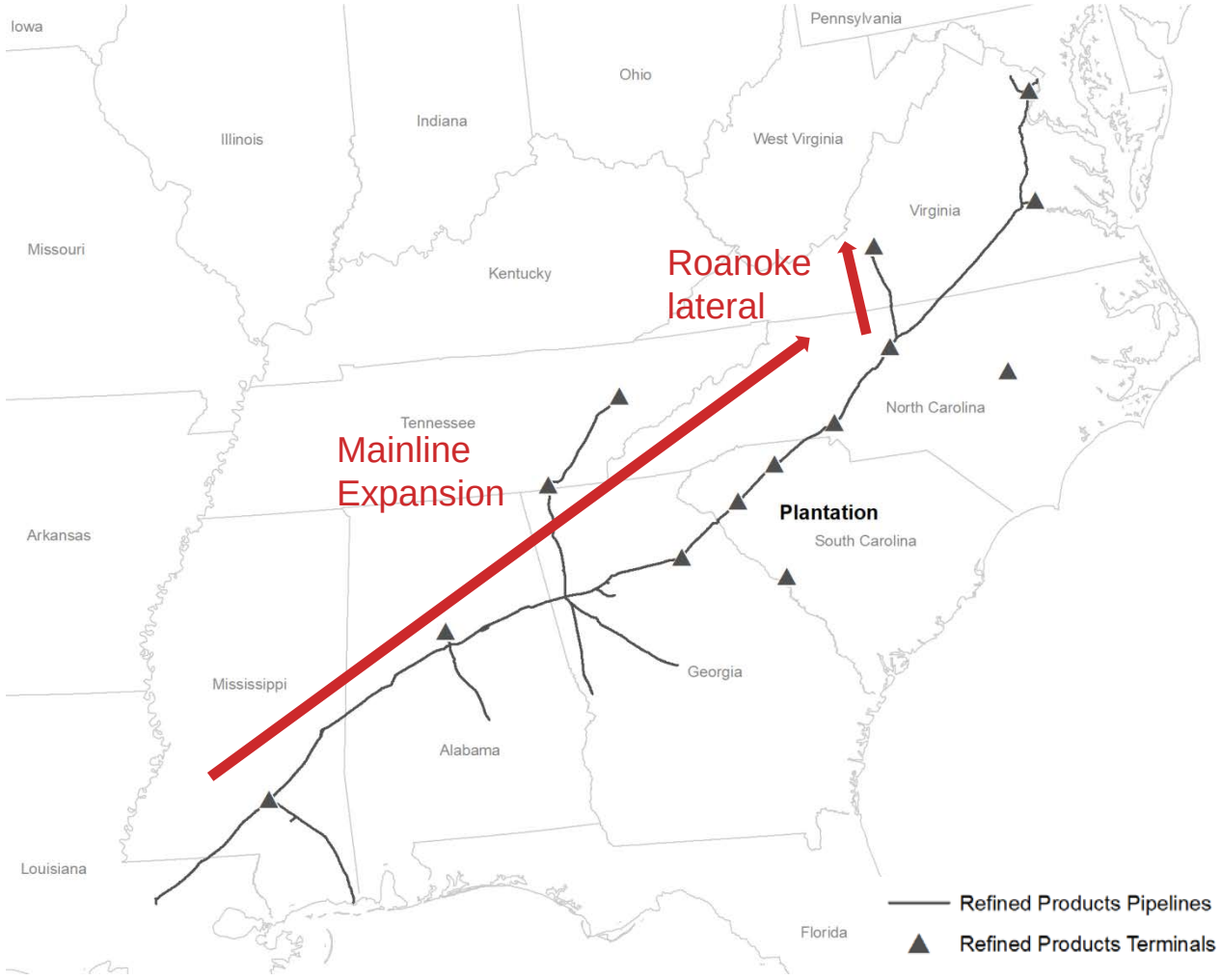
Securing refined products delivery for the Roanoke / Montvale area

Market Drivers

- Historically, both the Colonial Pipeline Montvale Lateral & Plantation Roanoke Lateral have served the Roanoke, Virginia market
- Abandonment of the Colonial Montvale Lateral has displaced 30-50 mbbld in the Roanoke & Montvale area, creating an opportunity for Plantation

Project Scope

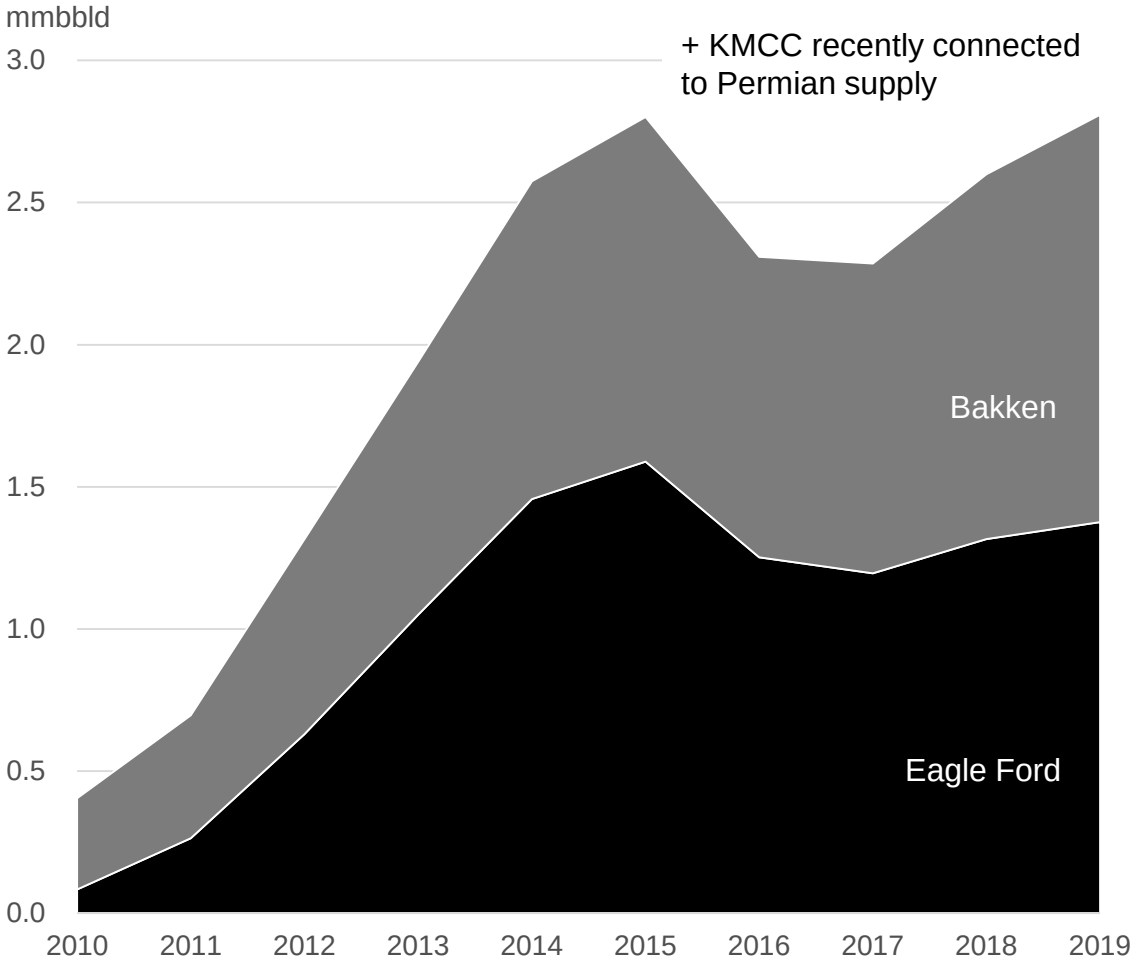
- ~21 mbbld expansion on Plantation Pipeline system
  - Expansion includes mainline & delivery lateral
  - Secured by 20 mbbld 10-year contracts with strong credit-worthy counterparties
- Serving the Roanoke & Montvale market in Virginia with origin points in Louisiana & Mississippi
- Also expanding terminals at Roanoke locations to handle additional throughput
- ~$35 million investment (KM share)
- Mainline expansion to Greensboro in-service
  - Capacity expansion on Roanoke lateral expected in service by April 2020



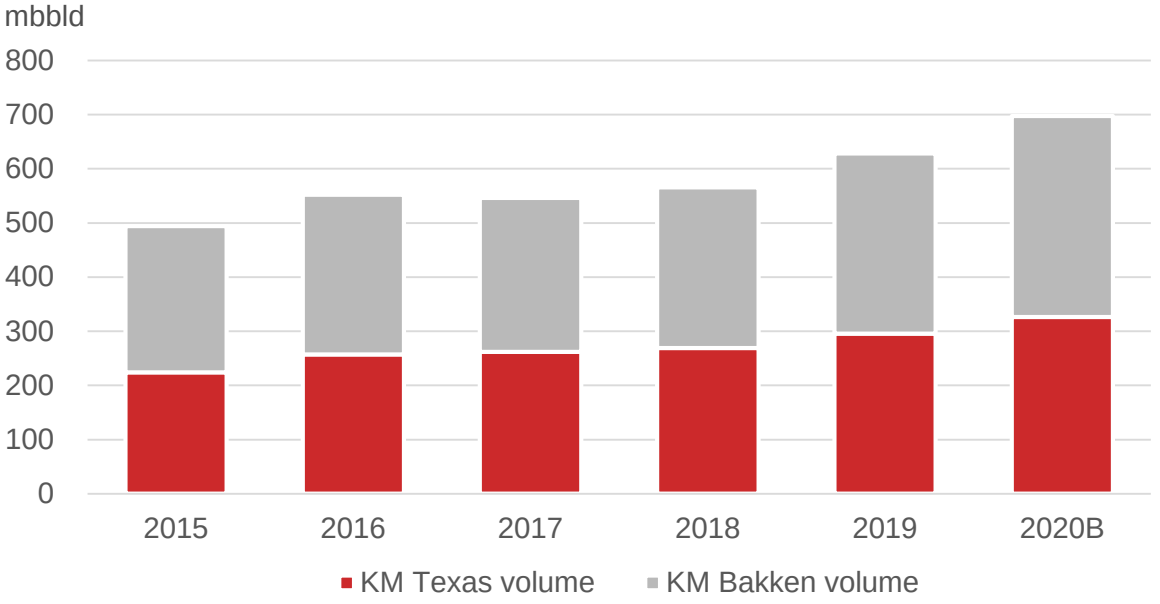
Strong Volume Growth Across Crude Pipelines

84% of 2020B volumes reflect re-contracted market rates

CRUDE OIL PRODUCTION BY BASIN SERVED[a]



THROUGHPUT VOLUMES BY CRUDE PIPELINE



KM Texas & Bakken pipelines CAGR[b] of

6.2%

>

Eagle Ford & Bakken Production CAGR[b] of

0.1%

Note: Bakken volumes include Hiland Crude Gathering & Double H Pipelines. Texas volumes include Double Eagle Pipeline & KMCC.

a) Source: U.S. EIA Drilling Productivity Report, Nov 2019.

b) CAGR calculated from 2015 through 2019.

Texas Crude Oil Assets: KMCC, Double Eagle & Splitter

Valuable connectivity to Corpus Christi & the Houston Ship Channel

Assets offer connectivity to the Corpus Christi & Houston Ship Channel markets

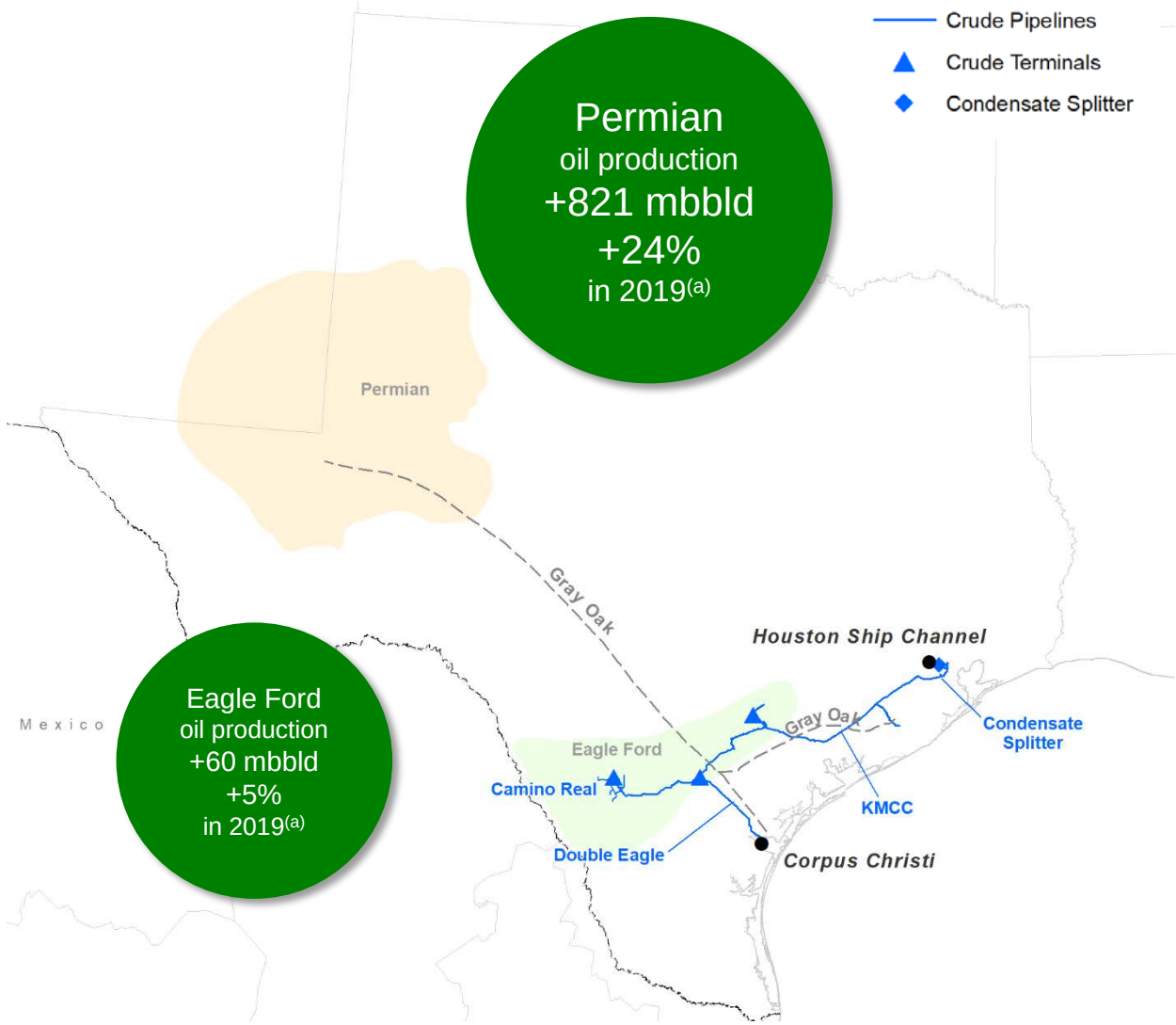
- Flexibility to reach domestic refining capacity & export facilities

Recent KMCC connection & mainline expansion allow for delivering Permian Basin volumes into Houston market under joint tariff service with Gray Oak pipeline[(b)]

- Expansion capacity created ability to deliver up to 100,000 bbl of crude oil from the Permian to markets in the Houston ship channel
- Early in-service connection became operational in the fourth quarter of 2019
  - Full in-service pending completion of Gray Oak Pipeline

Splitter fully contracted & running at capacity

2020B assumes 11% year-over-year increase in pipeline volumes transported

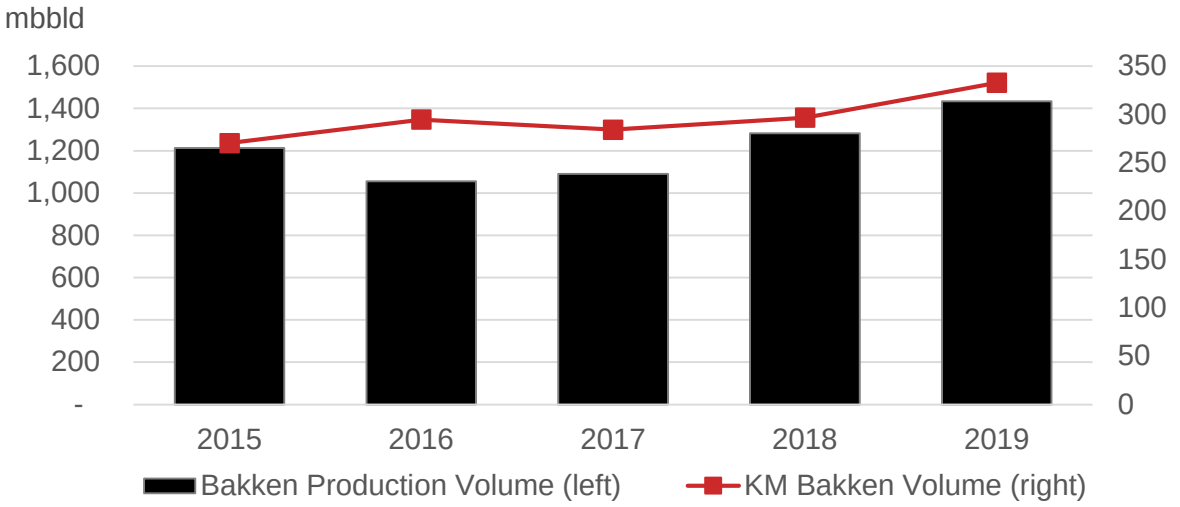


a) Source: U.S. EIA Drilling Productivity Report, Nov 2019.
b) Gray Oak pipeline is under construction by Philips 66 Partners.

Bakken Crude Oil Assets: Hiland Gathering & Double H

Strong production growth in the Bakken translating into higher transport volumes

BAKKEN BASIN PRODUCTION(a) & KM BAKKEN CRUDE VOLUMES(b)



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 to capture incremental production

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

- Joint tariff with Pony Express provides access to Cushing
- Recent open season secured long-term contracts for delivery into Cushing

KM Bakken volume CAGR(c) of

Bakken Production CAGR(c) of

5.3% > 4.3%

2020B assumes 12% year-over-year increase in volumes transported

a) Source: U.S. EIA Drilling Productivity Report, Nov 2019.
b) KM Bakken Crude volumes includes Hiland Crude Gathering & Double H Pipeline.
c) CAGR calculated from 2015 through 2019.

Products Segment Snapshot

Asset statistics

Crude oil assets:	Statistics	Origin	Destination
KM Crude & Condensate pipeline (KMCC)	264 miles	Eagle Ford Shale Field in South TX (Dewitt, Karnes, Gonzales Counties)	Houston Ship Channel Refining Complex
Camino Real Gathering	68 miles	South Texas, Eagle Ford shale formation	
Double Eagle pipeline (50% JV)	204 miles	Eagle Ford	Corpus Christi & KMCC
Double H pipeline	512 miles	Bakken shale in Montana & North Dakota	Guernsey, WY
Hiland (Williston Basin)	1,595 miles	Bakken / Three Forks shale formations (North Dakota / Montana)	
Condensate Splitter	Two 50 mbbld units which split condensate into its various components; located in the Houston Ship Channel		
Refined products assets:			
Plantation Pipeline Company (51% JV)	3,182 miles	Louisiana & Mississippi	From Mississippi through Virginia incl. Tennessee
SFPP Pipeline System	2,845 miles	North Line: San Fran Bay area refineries Oregon Line: Portland Marine terminals West Line: Los Angeles Basin East Line: El Paso, TX	North Line: Northern CA & NV Oregon Line: Eugene, OR West & East Lines: Arizona San Diego Line: serves major population areas in Orange County & San Diego
CALNEV Pipeline System	566 miles	Colton, CA	Las Vegas, NV
Central Florida Pipeline (CFPL)	206 miles	Tampa, FL	Orlando, FL
Southeast Terminals	25 locations ~9 mmbbls capacity	From Mississippi through Virginia incl. Tennessee	
West Coast Terminals	38 miles 8 locations ~10 mmbbls storage capacity	Seattle, Portland, San Francisco & Los Angeles area terminals	
Transmix Facilities	~0.6 mmbbls tankage capacity	Colton, CA; St Louis, MO; Greensboro, NC; Woodbine, MD; Richmond, VA	

Terminals

Segment Presentation

Terminals Segment Overview

Diversified terminaling network connected to key refining centers & market hubs

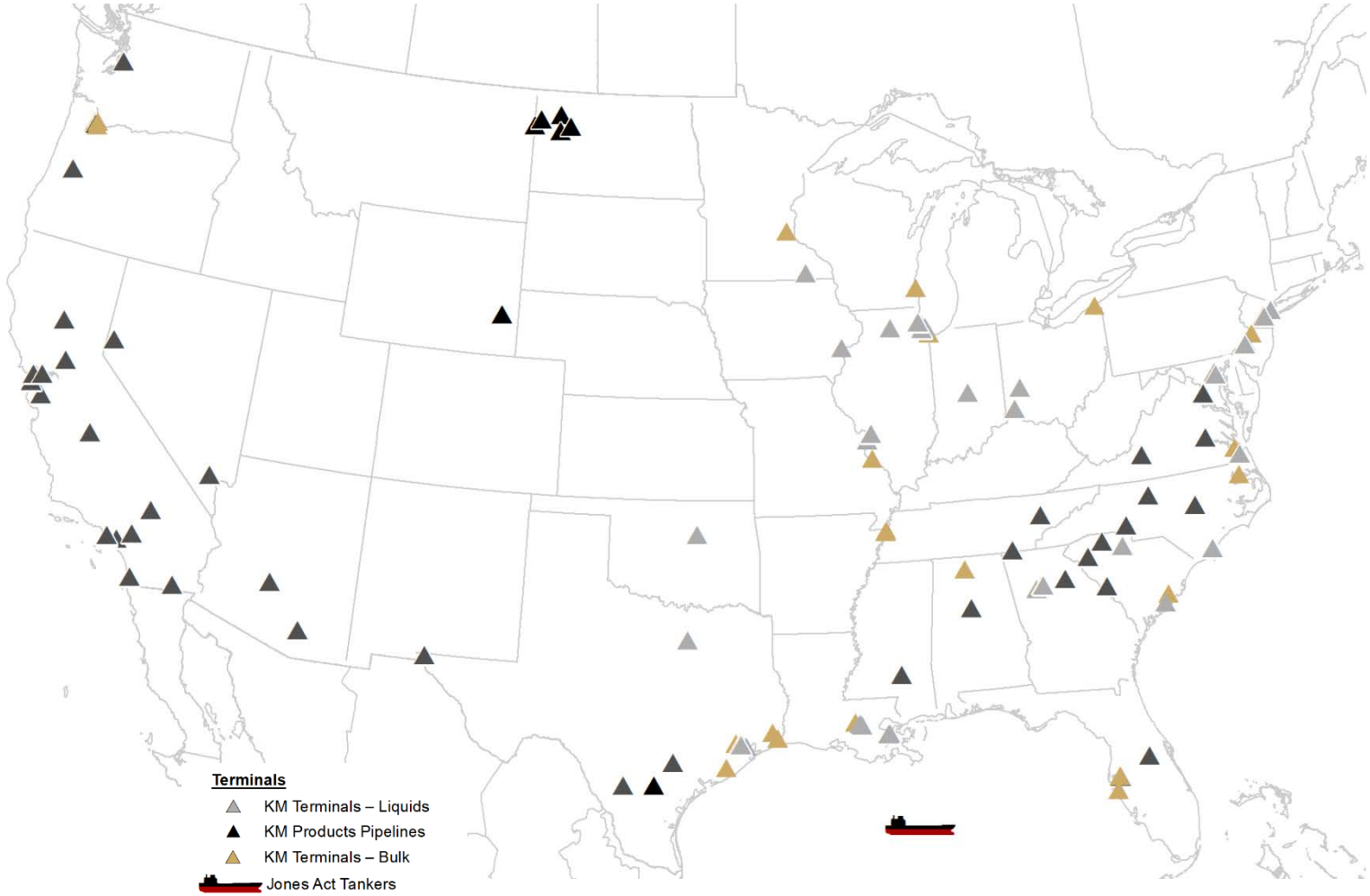
Asset Summary	# of terminals	capacity (mmbbls)
Terminals Segment – Bulk	32	
Terminals Segment – Liquids	50	79
Products Pipelines Segment	65	55
Total	147	134
Jones Act:	16 tankers	

2020B EBDA[(a)]: $1.1 billion

Project Backlog:

$0.2 billion to be completed by 1Q2021[(b)]

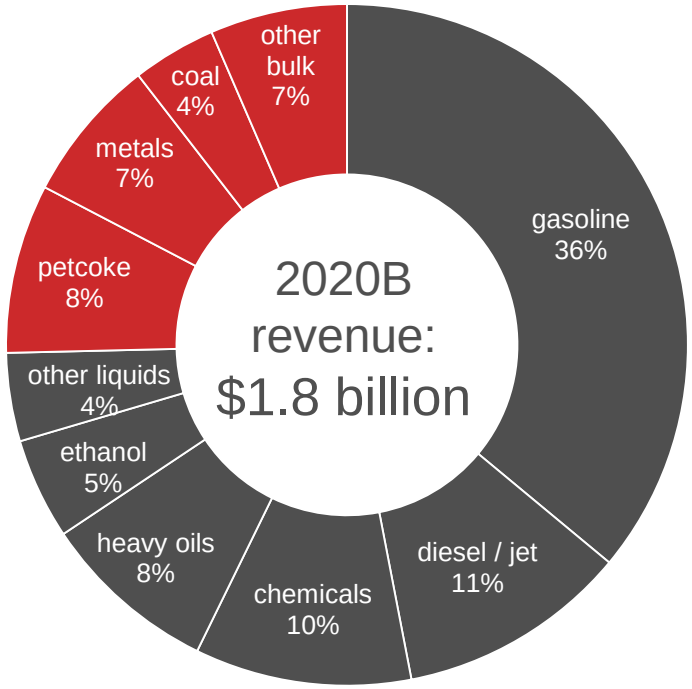
- Houston Ship Channel
  - Butane blending systems
  - Increased dock loading rates
  - Additional inbound connectivity
  - Low/High sulfur fuel oil segregation
- Chicago & New Orleans
  - Additional renewables storage
  - Modal efficiency enhancements



a) 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
b) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

Terminals Segment Product Mix

Diverse, liquids-focused product mix



liquids products 75%

- Domestic terminaling in both hub & regional markets
  - Premier refined products terminaling system in the Houston Ship Channel
  - Complementary chemicals & renewable products
- Domestic maritime Jones Act tankers
  - Refined products & crude on East & West coasts
  - Chemicals & renewables capable
- Organic growth through continued unmatched service offerings & flexibility to domestic & international markets

bulk products 25%

- Export & import capabilities in multiple bulk commodity products, including petroleum coke, coal, copper, ores, soda ash & other
- Organic growth through increasing international trade

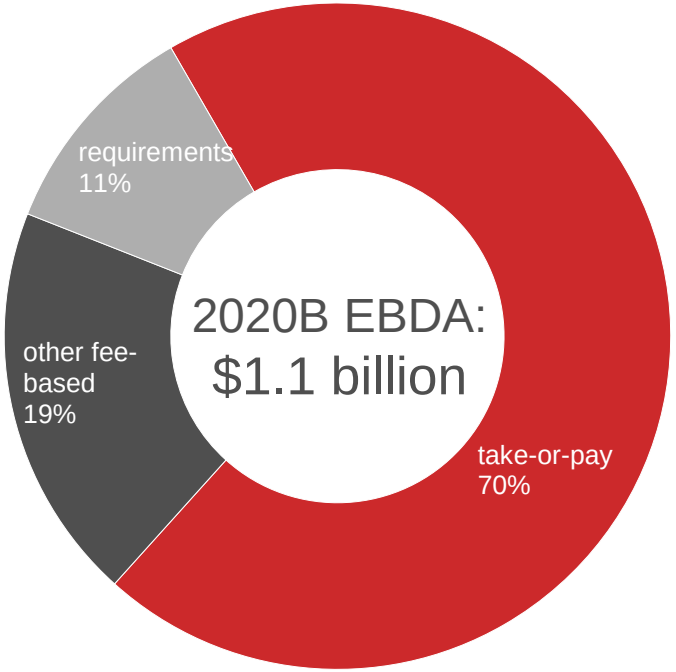
Revenues driven by refined products, chemicals & renewables

Complementary & synergistic bulk commodity services

Note: 2020 budgeted Terminals Segment revenues

Terminals Segment Contract Model

Earnings driven by long-term contractual use of our assets



take-or-pay 70%

- Leased tank capacity (pre-paid monthly)
- Jones Act tanker charters (pre-paid monthly)
- Minimum volume commitments (per bbl or ton)

other fee-based 19%

- Ancillary services (e.g., vessel loading & blending)
- Based on customer use (per bbl or ton)
- Secured by customer & market needs

requirements 11%

- Fee-based
- Ratable – tied to customer production levels
- Refineries – petroleum coke production
- Steelmaking – Nucor in-plant services

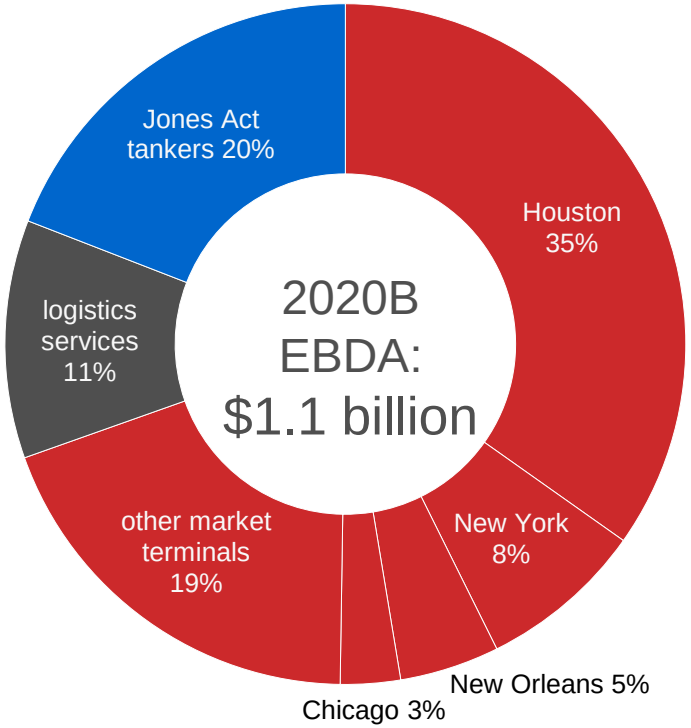
Stable fee-based earnings stream

Top-10 customers are investment grade & represent ~50% of Terminals revenues

Note: 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations

Terminals Segment Services

Providing customers with value-added service solutions & access to markets



terminaling services 69%

- Concentrated in key markets
- Primary Hubs: Houston & New York Harbor
- Secondary Hubs: New Orleans area & Chicago
- Regional terminals complement the hub positions
- **Advantaged connectivity to markets**

logistics services 11%

- Logistics services directly tied to customer operations
- In-plant handling of steel, scrap & ores supporting steel production
- Petroleum-coke handling supports customer refinery operations
- **Utilizes operating competencies & efficiencies**

Jones-act tankers 20%

- 16 Jones Act tankers under term charters
- Serving refining industry in both domestic crude oil & refined products
- Complementary to marine terminaling business
- **Modern & efficient fleet**

Full offering of supply chain logistics – terminaling, logistic services & shipping

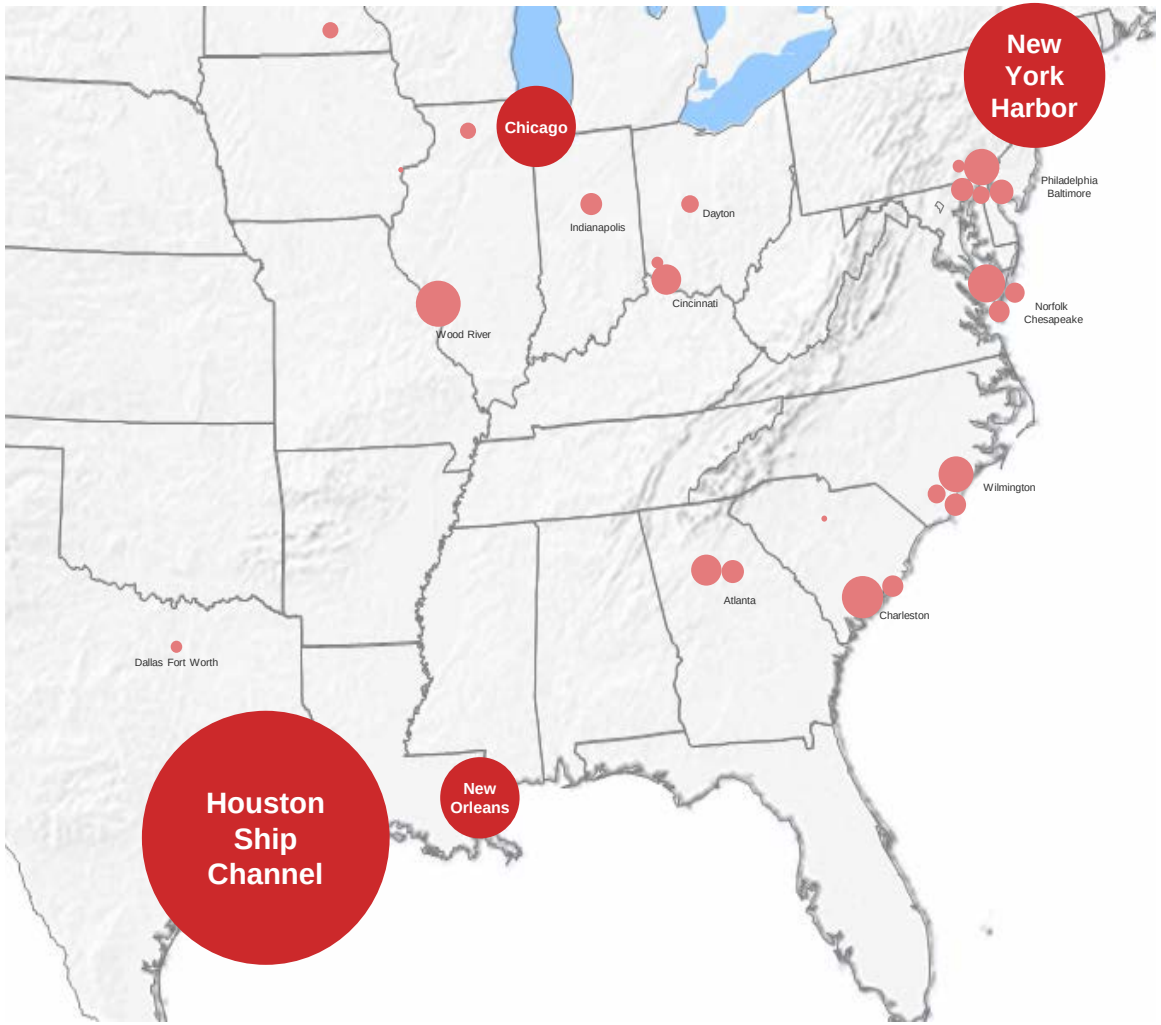
Note: Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

Terminals Segment Key Hubs

Strategically located

- **Houston Ship Channel**
  - Premier refined product terminaling & blending system
  - 9 terminals providing ~43 million barrels of capacity[a]
  - $364 million 2020B EBDA[b]
- **New York Harbor**[c]
  - Gasoline blending hub balancing domestic & international supply
  - 4 terminals providing ~14 million barrels of capacity
  - $82 million 2020B EBDA[b]
- **New Orleans**
  - Lower Mississippi River terminals serving growing chemical & renewable markets
  - 5 terminals providing ~5 million barrels of capacity
  - $49 million 2020B EBDA[b]
- **Chicago**
  - National clearinghouse, pricing & trading hub for ethanol
  - 4 terminals providing ~5 million barrels of capacity
  - $30 million 2020B EBDA[b]

~80 million barrel system critical to our customers



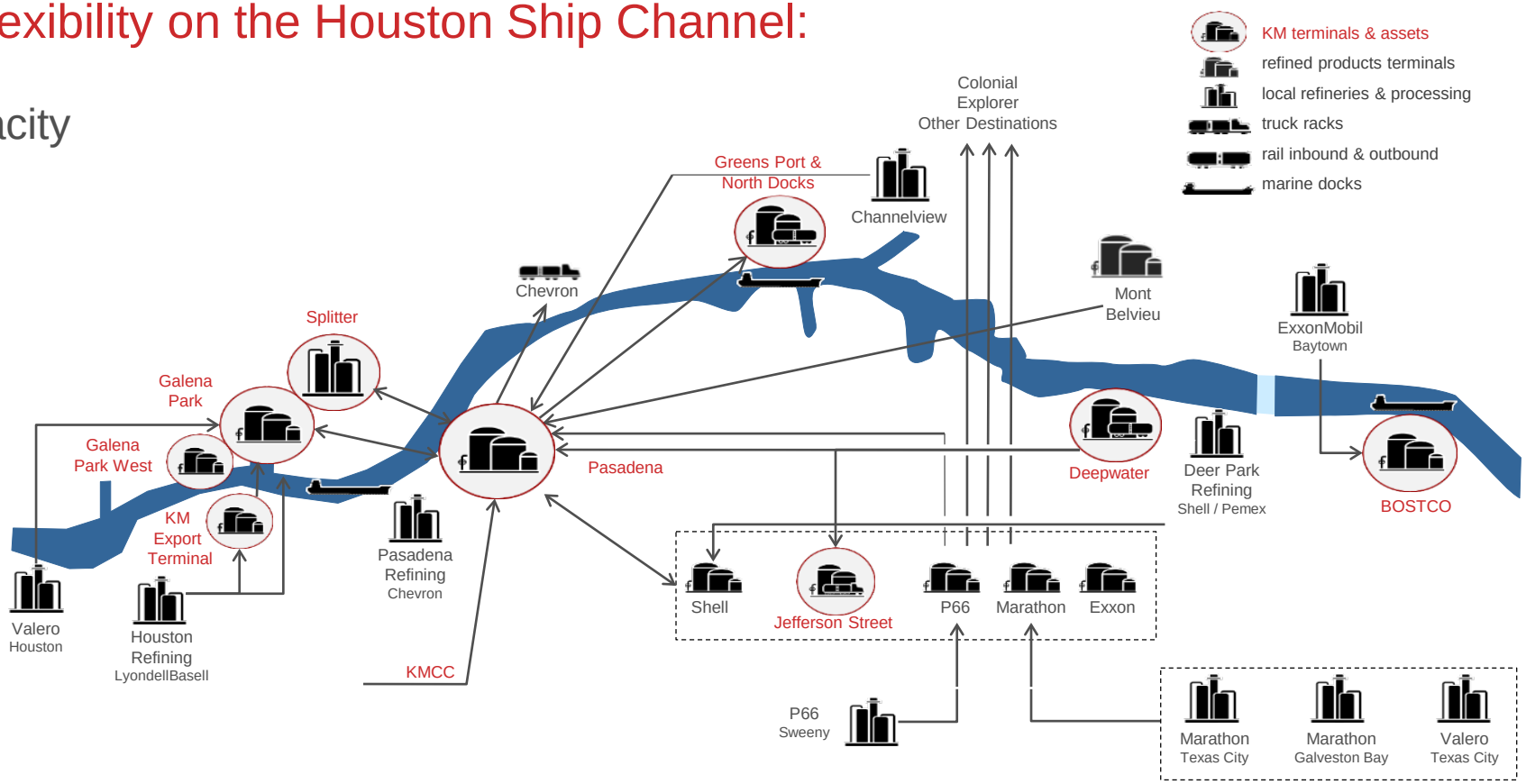
a) Houston capacity includes tankage associated with Products Segment splitter at Galena Park; capacities represented on a gross basis.
b) 2020 budgeted Adjusted EBDA. Note: $1.1 billion total Terminals Segment 2020B Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
c) New York Harbor excludes Staten Island which is held for sale

Integrated Terminaling Network Focused on Refined Products

Irreplaceable collection of assets, capabilities & market-making connectivity

Our unmatched scale & flexibility on the Houston Ship Channel:

- **43** million barrels total capacity
- **29** inbound pipelines
- **18** outbound pipelines
- **16** cross-channel pipelines
- **11** ship docks
- **38** barge spots
- **35** truck bays
- **3** unit train facilities



~$2.0 billion invested since 2010

Note: asset metrics include projects currently under construction

Full Service Offering in the Houston Ship Channel

Industry clearinghouse for production & markets

Unmatched inbound connectivity

Refineries

Pipeline connectivity to all HSC refineries providing gasoline, distillate & blendstock supply

- Pasadena
- Galena Park
- Kinder Morgan Export Terminal
- BOSTCO

Chemicals

Pipeline & barge receipts of chemicals & gasoline blending components

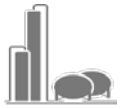
- Pasadena
- Galena Park

Ethanol

Unit train receipts of domestic ethanol production

- Deer Park Rail Terminal
- Pasadena
- Jefferson Street Truck Rack

Mont Belvieu NGLs



Pipeline connectivity to Mont Belvieu fractionators for butanes & natural gasoline

- Pasadena
- Galena Park

Value-added services

Aggregation, staging & storage services

Gasolines & Distillates
Black Oils
Chemicals
Renewables

Pasadena, Galena Park, BOSTCO, Kinder Morgan Export Terminal, Deer Park Rail Terminal, Jefferson Street Truck Rack, et al.

Product blending services

Gasolines & Distillates

Pasadena
Galena Park
Kinder Morgan Export Terminal

Bunker blending services

Residual Oils
Black Oils
Distillates

BOSTCO

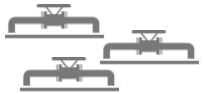
Outbound market access

Truck Rack

Local truck rack loadings local markets

- Jefferson Street Truck Rack

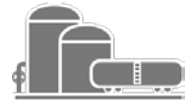
Pipelines



Pipeline origination to domestic markets

- Pasadena
- Galena Park

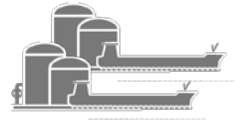
Rail



Unit train origination of refined products to Mexico

- Greens Port

Marine



Docks for export, as well as Jones Act domestic shipments

- Pasadena
- Galena Park
- BOSTCO
- Kinder Morgan Export Terminal
- North Docks

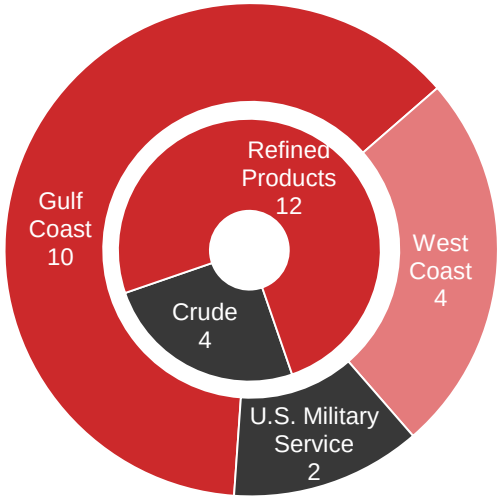
"More than just a bucket" – value-added solutions for trading, blending, optimization & market access

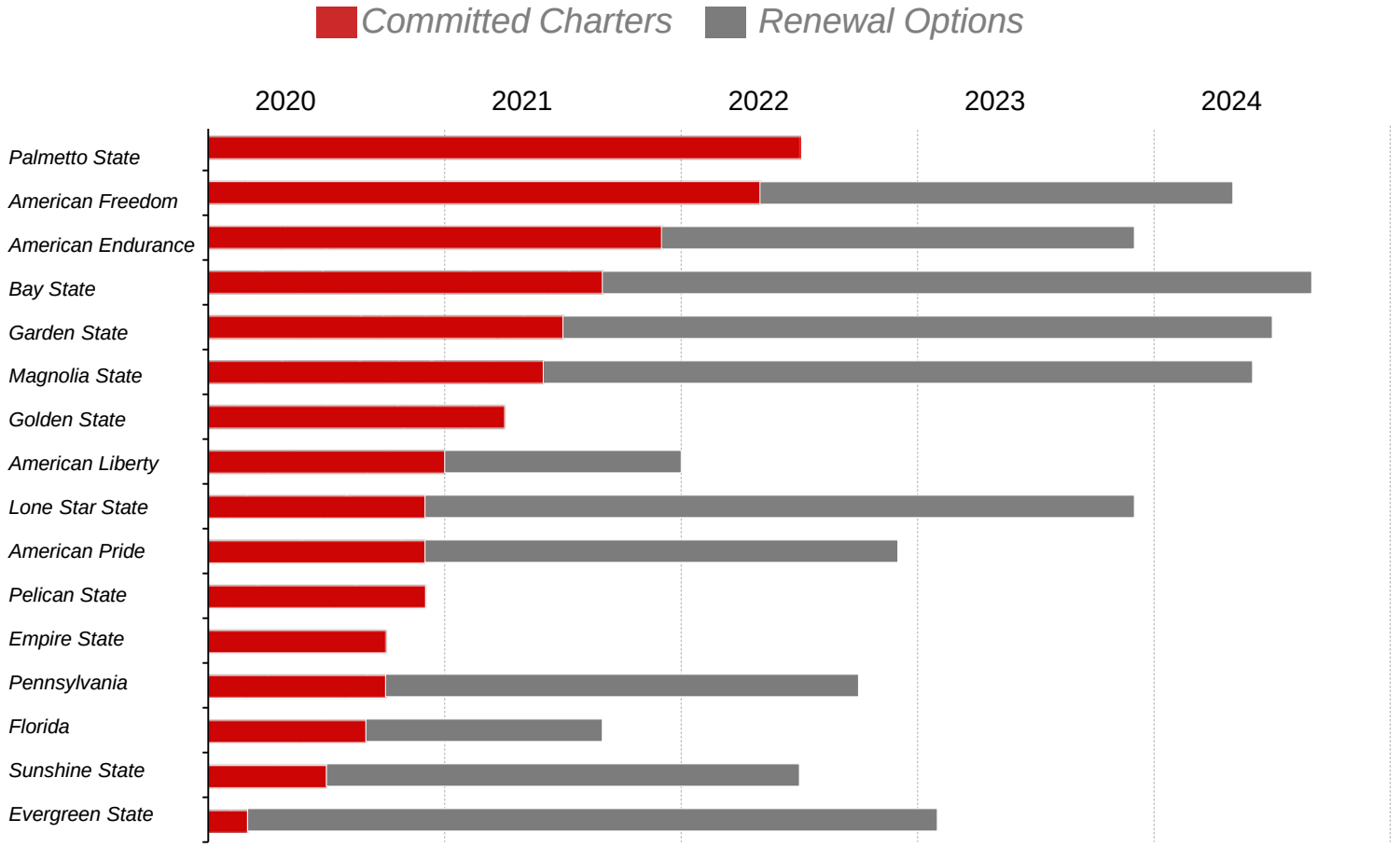
Positioned to Meet Domestic Maritime Demand

American Petroleum Tankers (APT) fleet of 16 medium-range tankers

- Improving charter rate environment
- Favorable supply & demand fundamentals
  - Refined product & crude oil trade
  - Military demand
  - Continuing industry retirements of older Jones Act tankers
  - Barriers to entry – regulatory & construction costs

KM Vessel Service





Most modern & efficient industry offering in both refined product & crude oil service

Bulk Commodities

Diversified product & services offerings

Petroleum Coke

One of the nation's largest handlers

8%
2020B Segment Revenue

- Handle ~40% of Midcontinent & Gulf Coast production
- In-plant refinery bulk-handling
- Export terminaling services
- Aggregation & blending at export terminals

Metals & Ores

Supporting steel manufacturing

7%
2020B Segment Revenue

- Feedstock ores & scrap
- Finished product handling of coils, plate, bar, billets & pipe
- Breakbulk imports & export terminals
- In-plant steel logistical services

Coal

Advantaged export positions

4%
2020B Segment Revenue

- U.S. coal exports
- Steam & metallurgical coal
- Highly efficient East & Gulf Coast terminals

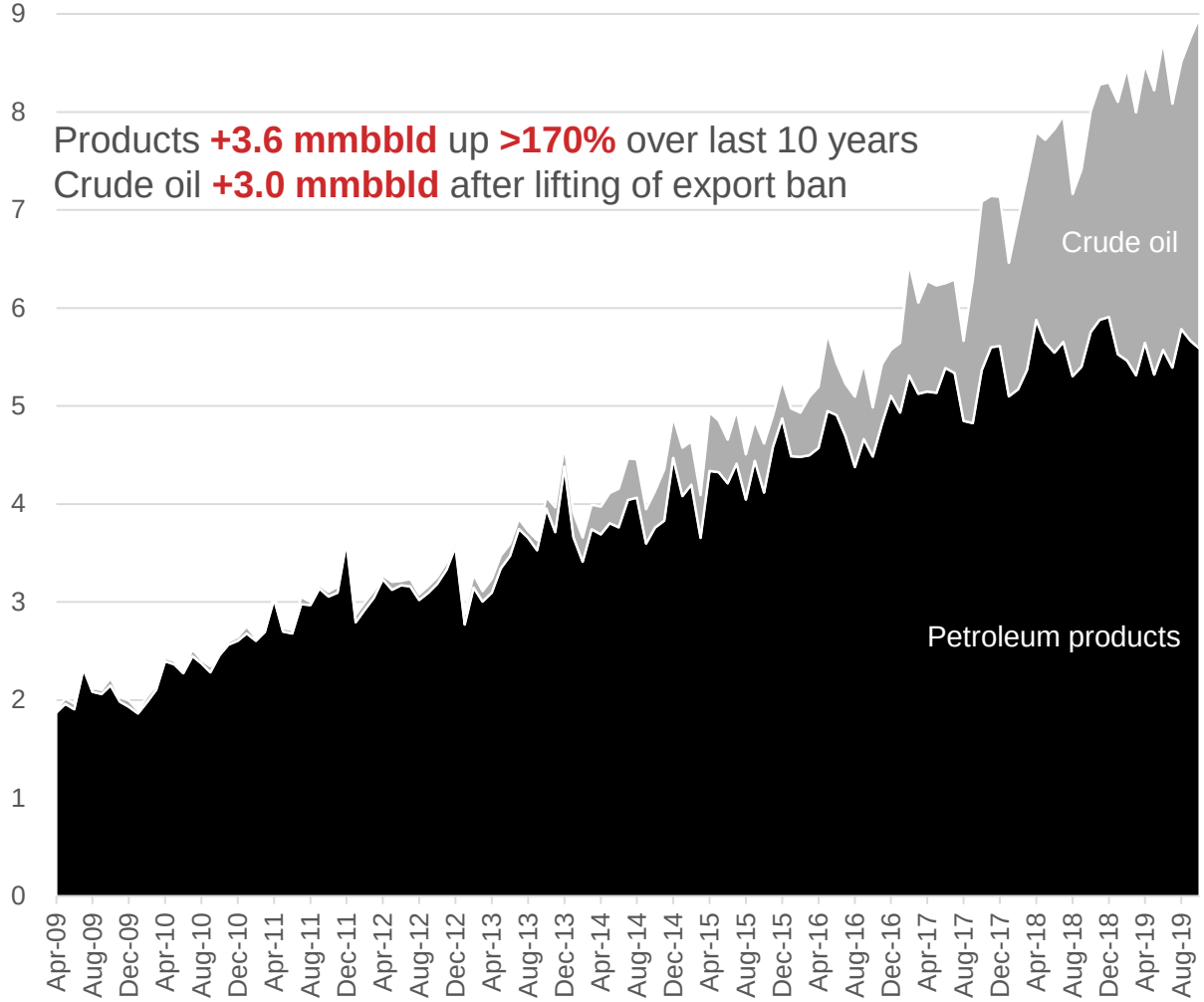
Note: 2020 budgeted Terminals Segment revenues of $1.8 billion, 25% from bulk products

Meaningful Growth in Exports of U.S. Petroleum Liquids

Competitive & growing U.S. supplies reach a diverse mix of global customers

U.S. EXPORTS OF PETROLEUM LIQUIDS

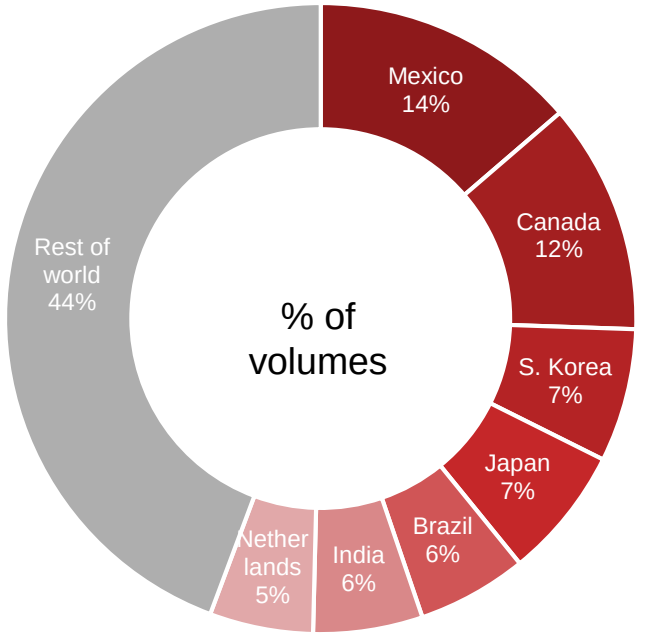
Millions of barrels per day



DESTINATIONS OF U.S. PETROLEUM LIQUIDS EXPORTS

Top 7 of 111 countries reached in January through October 2019

104 countries represent <1% each on average



Meaningful exports to North American & Asian markets

U.S. supplied ~9 million barrels per day of petroleum liquids to the global market in October

Source: U.S. Energy Information Administration (latest data available)

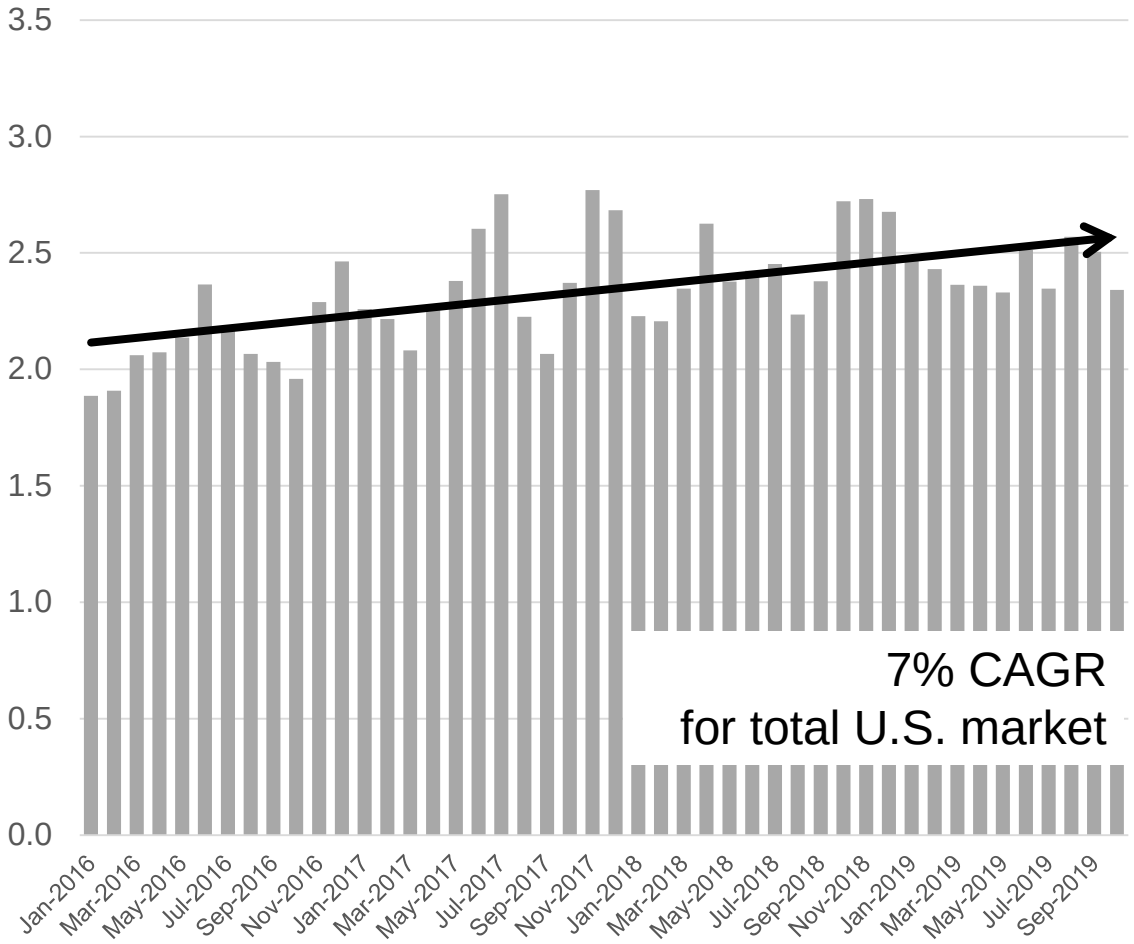
Note: Petroleum liquids includes finished petroleum products, crude oil, hydrocarbon gas liquids, unfinished oils, blending components, renewable fuels & oxygenates.

Leading Exporter of U.S. Gasoline & Distillates

Our Houston Ship Channel exports have grown faster than the broader U.S. market over the last several years

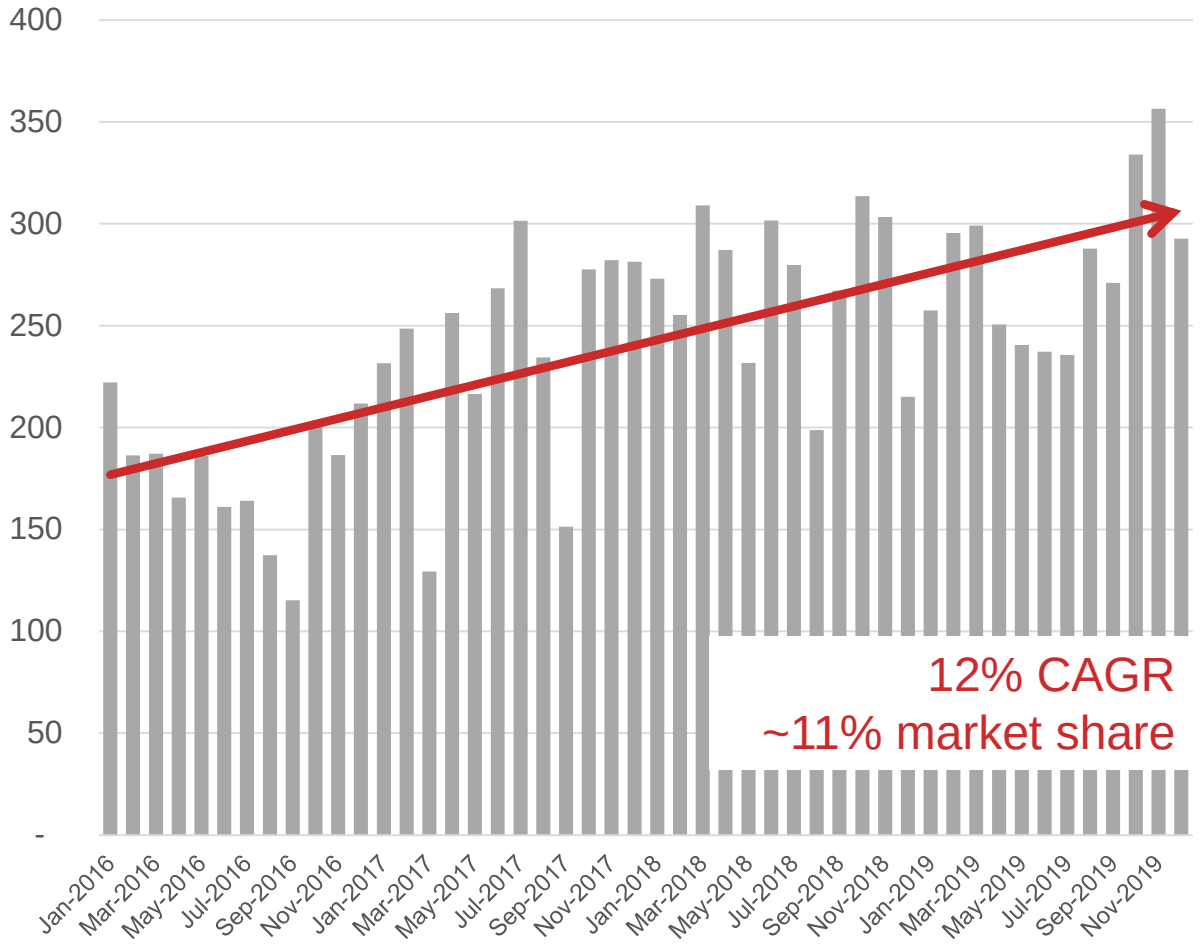
U.S. EXPORTS

Millions of barrels per day



KM EXPORTS FROM HOUSTON SHIP CHANNEL

Thousands of barrels per day



Source: U.S. Energy Information Administration, KM internal data

Note: Charts include distillate fuel oil, finished motor gasoline, gasoline blending components & jet fuel. CAGR calculated on a rolling 3-months basis beginning Q1 2016. KM market share calculated using internal data for KM export volumes & U.S. Energy Information Agency for U.S. export volumes for the 12 months ended October 2019 (latest EIA data available).

Macro Trends Translating to Growth

Long-term liquids fundamentals drive value on existing assets & present capital-efficient opportunity set

Market Growth	Terminals Opportunities	KM Response
Production crude oil, NGLs	**EXPORTS** refined products, chemicals by ship & rail crude oil & NGL diversification	▪ **Houston Ship Channel** – Enhancing butane/gasoline blending capabilities – Higher ship loading rates – Repurposed rail facilities for refined product exports to Mexico – Increasing inbound pipeline rates & connections – Allowing for IMO-2020 low-sulfur bunker segregations ▪ **Chicago / New Orleans Hubs** – Increasing ethanol tankage & storage capabilities – Improving truck, barge & rail connectivity & performance ▪ **Additional projects improving system efficiencies & capabilities**
Refining gasoline, jet, diesel	**BLENDING** blendstocks, butane capabilities	
Petrochemicals methanol, olefins, aromatics	**PROCESSING** hosting expansions at our terminals	
Renewables ethanol, biodiesel	**RENEWABLES** blending, transloading, supply chain	
	LOGISTIC SERVICES in-plant solutions	

Terminals Throughput & Tonnage Statistics

2019 vs. 2020B

Liquids Throughput

	Throughput		Variance	
MMBbls	**2019**	**2020B**	**MMBbls**	**%**
Gasoline	512.2	526.0	13.8	3%
Distillate	144.4	135.1	(9.2)	-6%
Petroleum Feedstocks	49.9	63.2	13.2	26%
Fuel Grade Ethanol/Biodiesel	47.9	50.4	2.5	5%
Chemical	44.5	49.0	4.5	10%
Vegetable Oils	6.4	9.0	2.6	40%
Other	3.7	4.0	0.2	6%
	809.1	**836.7**	**27.60**	**3%**

Bulk Tonnage

	Tonnage		Variance	
tons (millions)	**2019**	**2020B**	**mm tons**	**%**
Ores/Metals (Bulk)	15.6	15.7	0.1	1%
Petroleum Coke	13.8	14.6	0.8	6%
Coal	10.0	11.0	0.9	9%
Soda Ash	4.4	3.6	(0.8)	-18%
Aggregate	4.3	4.0	(0.3)	-7%
Salt	2.3	2.4	0.1	3%
Ores/Metals (Break-Bulk)	1.8	2.1	0.3	17%
Other Bulk	1.5	1.6	0.1	7%
Fertilizers	1.0	1.1	0.1	11%
Cement (Including Clinker)	0.6	0.8	0.2	36%
	55.3	**56.9**	**1.6**	**3%**

Notes: Excludes refined product or crude oil volumes through Jones Act tankers
Excludes divested assets in Canada & assets held for sale
Petroleum feedstocks includes crude oil, black oil & refinery intermediates

CO_2

Segment Presentation

CO_2 Segment Overview

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

CO_2 & TRANSPORT

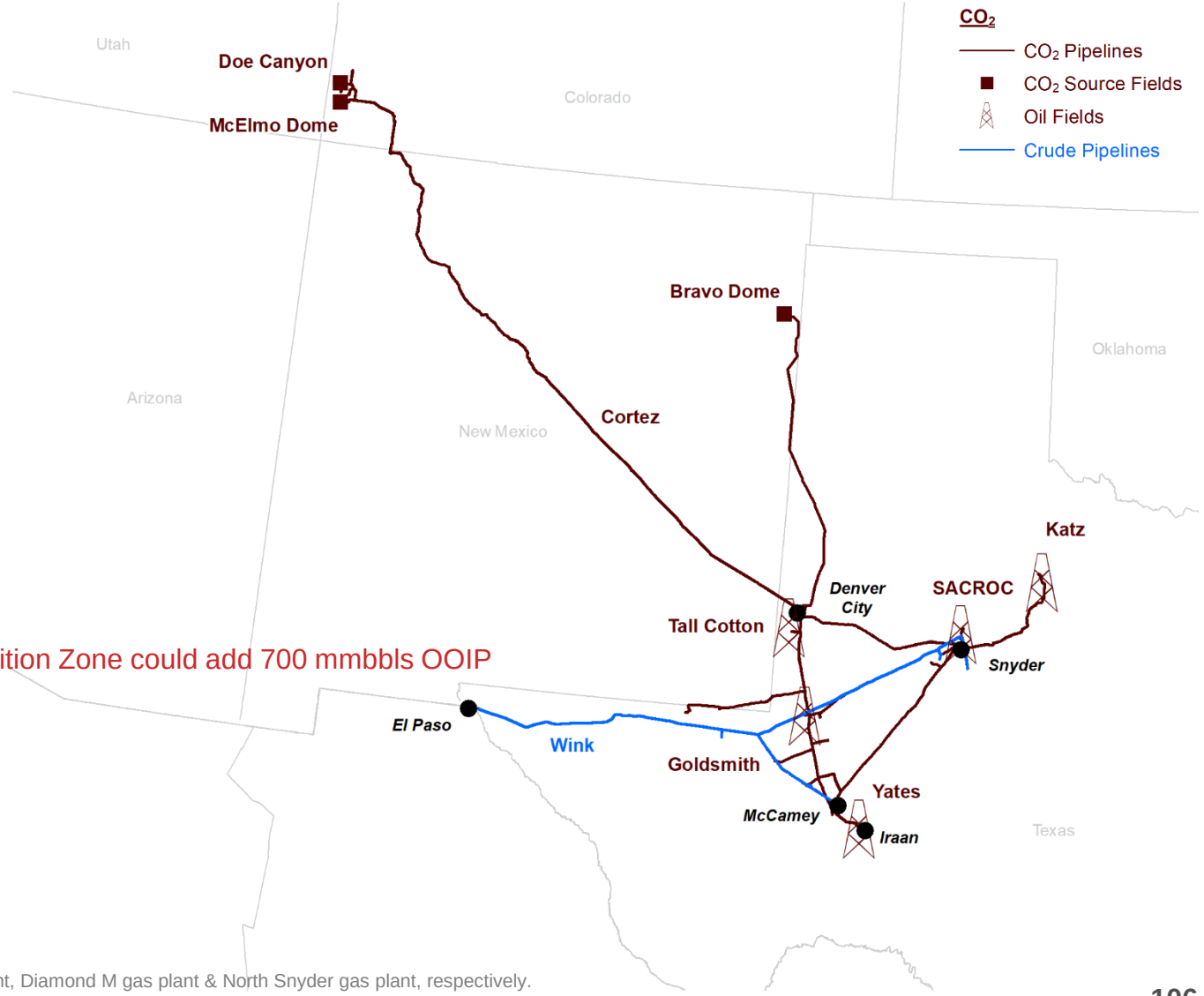
CO_2 Reserves	KMI Interest	NRI	Location	Est. OGIP (tcf)
McElmo Dome	45%	37%	SW Colorado	22.0
Doe Canyon	87%	68%	SW Colorado	3.0
Bravo Dome[a]	11%	8%	NE New Mexico	12.0

Pipelines	KMI Interest	Location	Capacity (mmcfpd)
Cortez	53%	McElmo Dome to Denver City	1,500
Bravo[a]	13%	Bravo Dome to Denver City	375
Central Basin (CB)	100%	Denver City to McCamey	700
Canyon Reef	97%	McCamey to Snyder	290
Centerline	100%	Denver City to Snyder	300
Pecos	95%	McCamey to Iraan	125
Eastern Shelf	100%	Snyder to Katz	110
Wink (crude)	100%	McCamey to Snyder to El Paso	145 mbbld

OIL & GAS

Crude Reserves[b]	KMI Interest	NRI	Location	Est. OOIP (billion bbls)
SACROC	97%	83%	Permian Basin	2.8
Yates	50%	44%	Permian Basin	5.0
Katz	99%	83%	Permian Basin	0.2
Goldsmith	99%	87%	Permian Basin	0.5
Tall Cotton	100%	88%	Permian Basin	0.7

Transition Zone could add 700 mmbbls OOIP



2020B EBDA[c]: $763 million

Note: OGIP = Original Gas In Place. OOIP = Original Oil In Place.

a) Not KM-operated.

b) In addition to KM's interests above, KM has a 22%, 51% & 100% working interest in the Snyder gas plant, Diamond M gas plant & North Snyder gas plant, respectively.

c) 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

Enhanced Oil Recovery Process

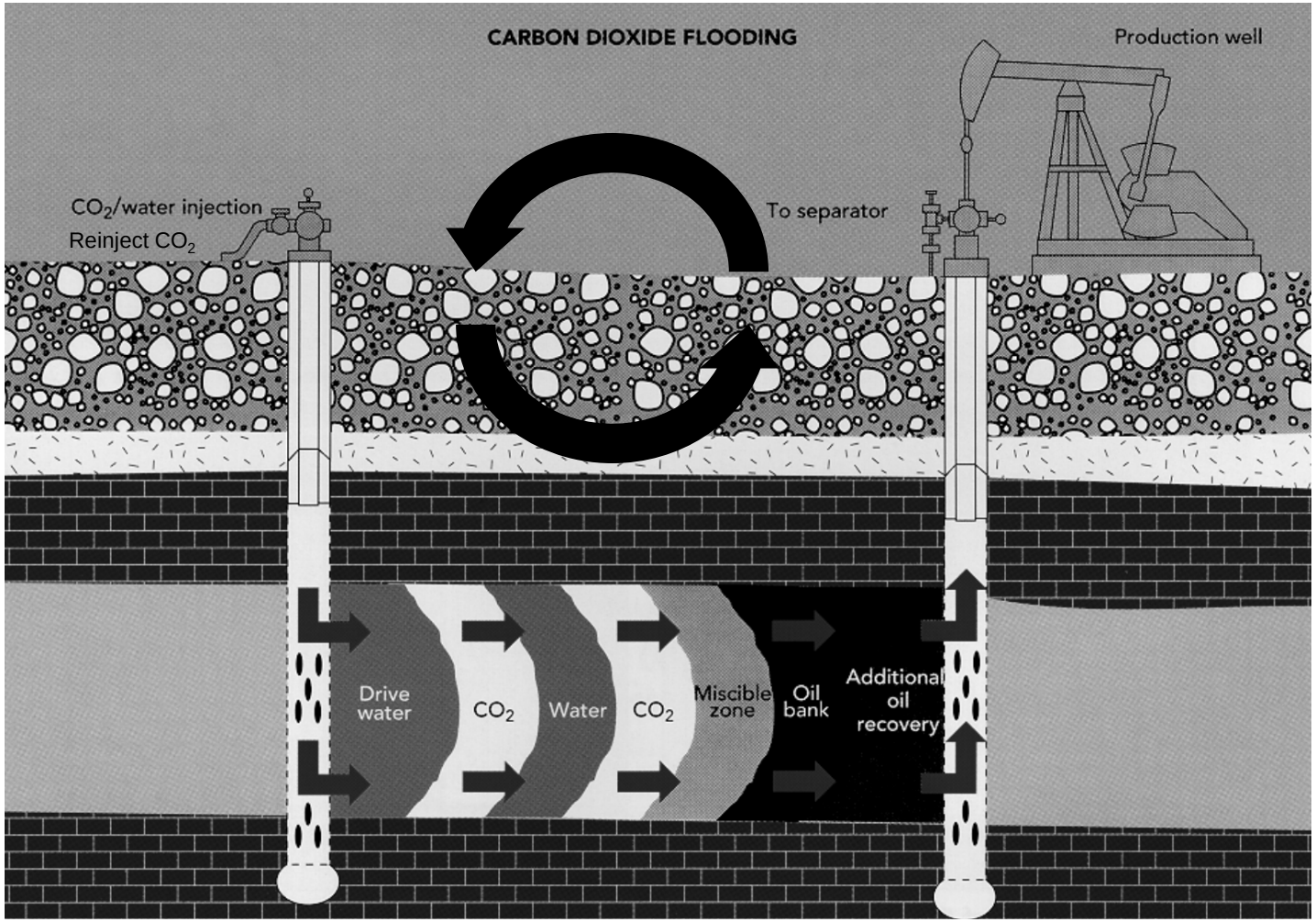
Specializing in the gas injection method of enhanced oil recovery

Three phases of oil & gas production

PRIMARY RECOVERY	SECONDARY RECOVERY	TERTIARY (ENHANCED) RECOVERY
10% OOIP recovered	20-40% OOIP recovered	30-60% OOIP recovered
Natural pressure from reservoir drives oil to pumps	Gas injection & waterflooding with goal to maintain reservoir pressure	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_2
  - Accounts for nearly 60 percent of U.S. EOR production



Own & operate naturally occurring CO_2 source, pipelines & oil fields in the Permian

Source: DOE, https://www.energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery

Key Factors Driving the Success of Our CO_2 Segment

Maximizing returns through financial discipline & innovation

Advantaged Assets

- Vertically integrated & Permian focused
- Produce & transport >80%[(a)] of the CO_2 delivered into the Permian
- Upside potential – history of extending productive life of fields
- Attractive consolidation opportunities
- CO_2 supply will lead to additional tertiary recovery
- Positioned for carbon capture future 45Q opportunities

Highly-Skilled Team

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

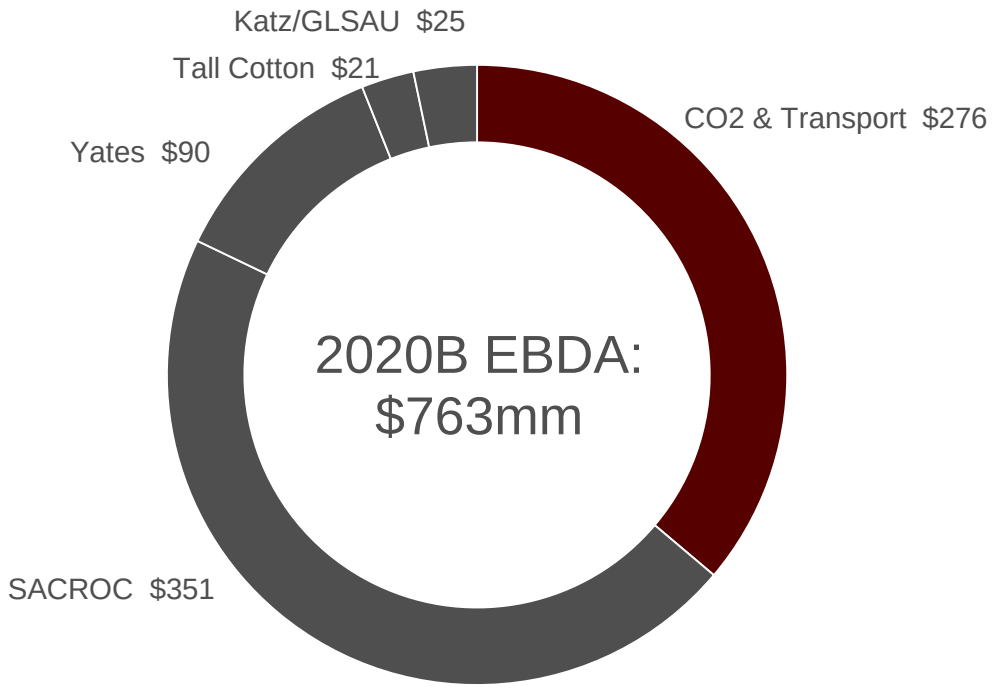
Profit-Focused

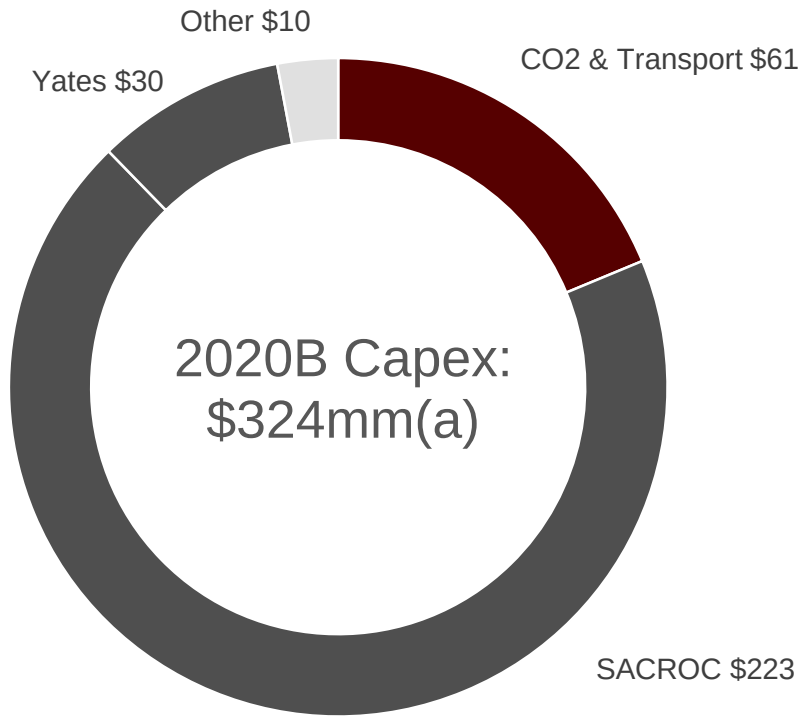
- High-return asset base
- Invest based on project economics – not to maintain production
- Manage commodity price volatility with consistent hedge policy
- Healthy operating margins driven by low cost structure
- Meaningful free cash flow & profitable through commodity cycles

a) KM data & EPA.

CO_2 Segment Budget & Sensitivities

Positive CO_2 Free Cash Flow





Oil Price & Volume Sensitivity Δ	2020B DCF impact
$1/bbl WTI	NGL: $0.8mm CO_2: $0.6mm Crude: $1.3mm **Total: $2.7mm**
1% NGL / crude ratio[b]	$1.8mm
$0.01/bbl Mid / Cush Diff	$0.02mm
500 bopd in SACROC, Katz, GLSAU, or Tall Cotton	$8.1mm
500 bopd in Yates	$4.2mm
50 mmcfd in CO_2	$7.6mm

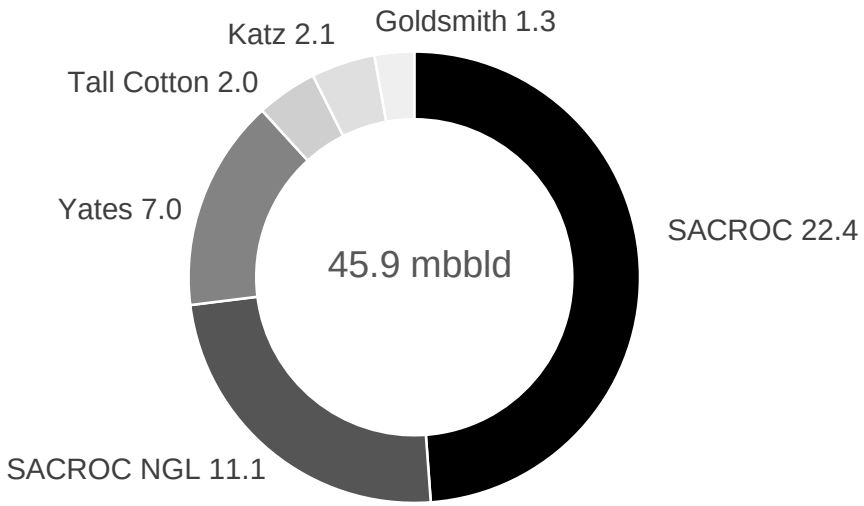
Proven capital discipline

2020B CO_2 Free Cash Flow: $423 million

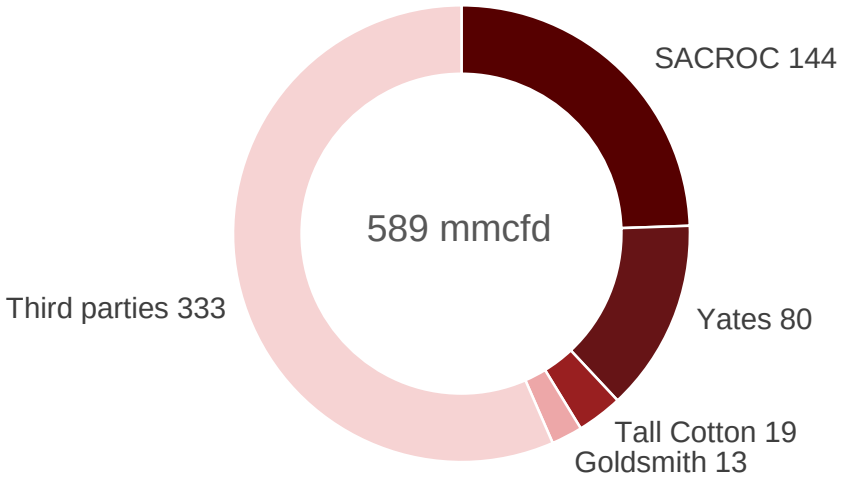
Note: 2020B Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
a) Total capex includes capitalized CO_2. Other includes Katz, Goldsmith & Tall Cotton.
b) Budgeted NGL / crude ratio of 37%.

CO_2 Segment Budgeted Volumes & Highlights

2020B NET OIL & NGL PRODUCTION
mbbld



2020B NET CO_2 SALES
mmcfd



OIL & GAS

- Majority of required takeaway capacity provided by KM-owned Wink pipeline
- ~86% of 2020B oil production hedged to WTI price
- Mid-Cush differential applies to ~32.6 mbbld of the 2020B oil production, of which 31.1 mbbld (or 96%) is hedged

CO_2 & TRANSPORT

- Supplies >80% of CO_2 to Permian including 100% to KM oil & gas business
- 100% of 2020B CO_2 production is contracted, including 84% subject to minimum volume commitments
- ~9 years weighted average remaining contract life with third parties

CO_2 Segment 2020 Oil & Gas Major Projects

Major projects expected to generate attractive returns in multiple commodity price environments

Asset	Project	2020B capex	Commentary	ATIRR% at flat WTI price scenarios		
				Forward Curve	$55	$60
SACROC	West Shore	$136mm	■ Activate 28 of 33 Conventional Project Area Patterns (19% Transition Zone)	19%	22%	28%
SACROC	Other	$79mm	■ Complete 5 Bypassed Pay Zonal Horizontal Producers ■ Activate 1 Vertical Bypassed Pay Injection Project (4 patterns) ■ Execute +/- 30 Conformance Projects	39%	36%	45%
Yates	Horizontal Drain Hole Program & Other	$30mm	■ Drill 40 Horizontal Drain Hole wells ■ Continue Surfactant stimulations ■ Execute on pilot of second phase horizontal drain hole program	63%	69%	83%

Note: 2020B capex includes related CO_2 purchases. Forward curve strip price as of 01/08/2020.

Extending Productive Life of Mature Fields

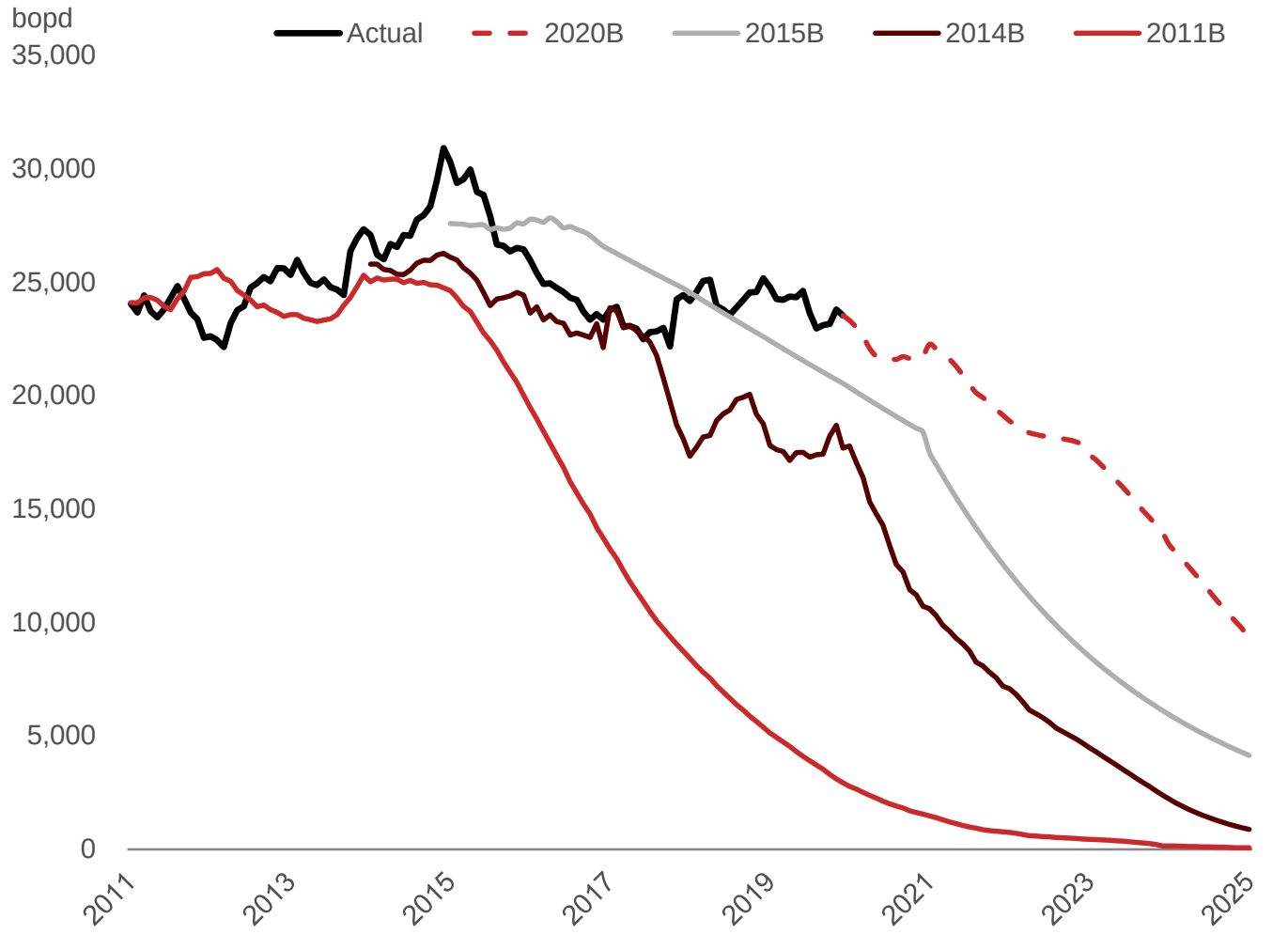
Innovation & team work continue to push SACROC decline curve flatter

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
  - Transition Zone is the next incremental opportunity at SACROC & could add 700 mmbbls to the OOIP estimate
- 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

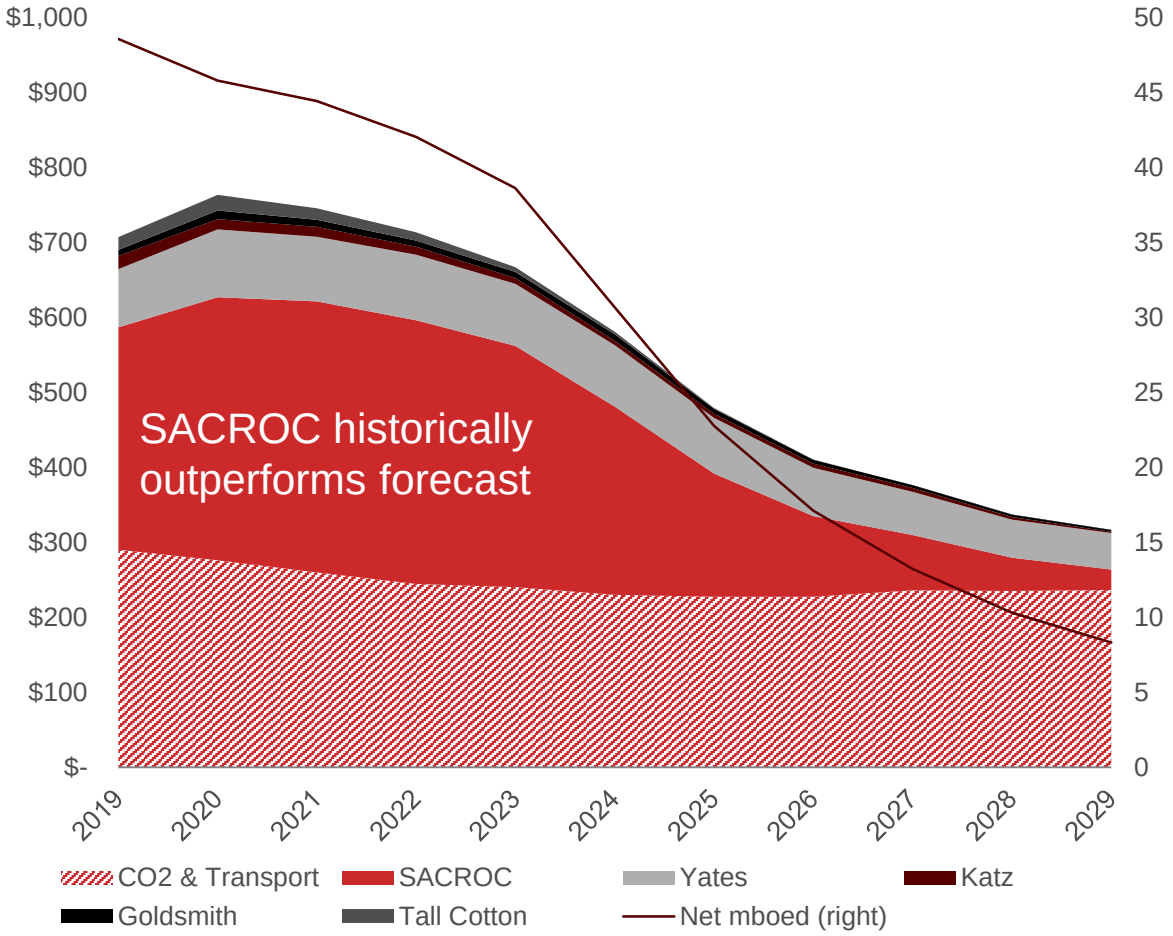


CO_2 Segment Long-Term Growth Outlook

Projected EBDA, net production & development plan

EBDA[(a)]

$ millions



NET PRODUCTION

incl. NGL & residue gas (mboed)

10 YEAR DEVELOPMENT PLAN: 2020 – 2029

Asset	Net Production (mmboe)	KM Share CapEx ($mm)	Expansion Program Plans
SACROC	69	$765	■ Develop West Shore ■ Bullseye redevelopment into Phase 3 ■ Develop other transition zone projects ■ Expand zonal horizontal producer program
Yates	20	148	■ Continue Horizontal Drain Hole programs ■ Evaluate other EOR methods ■ Continue Surfactant Treatment Program
Tall Cotton, Katz & GLSAU	11	44[(b)]	■ Optimize flood performance ■ Evaluate expansion opportunities at Tall Cotton, Katz & Goldsmith
Oil & Gas Total:	100	$957	
CO_2 & Transport		482	■ Maintain capacity in existing source fields (McElmo & Doe Canyon) ■ Optimize development capital to meet future demand
Total:		$1,439	

Note: 2020B Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

a) Segment EBDA excludes intersegment eliminations related to CO_2 purchase profits. Assumes crude oil price of $55 / bbl in 2020 & $60 / bbl thereafter.

b) Tall Cotton, Katz & Goldsmith capitalized CO_2.

CO_2 Free Cash Flow & Attractive Returns

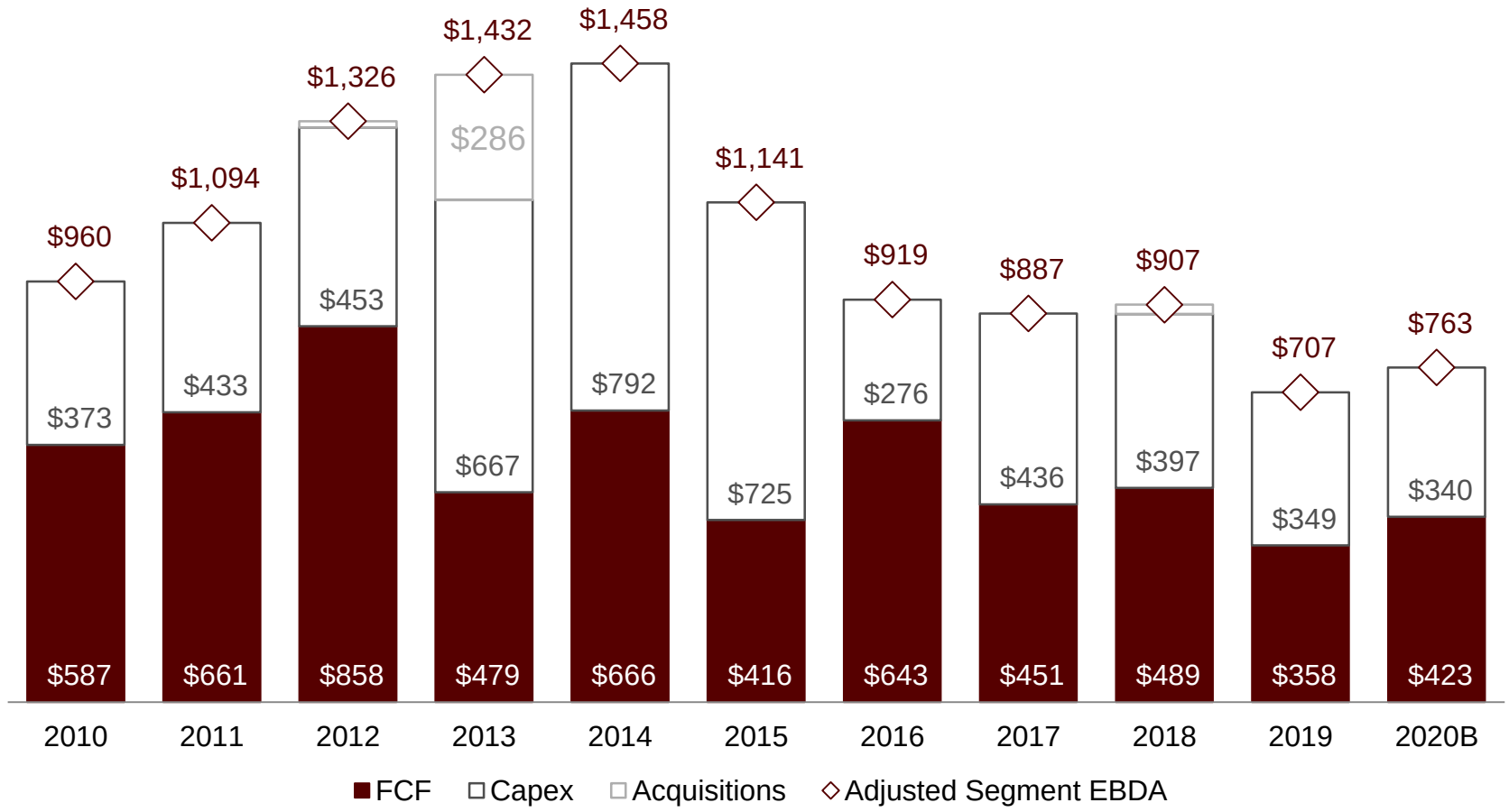
Long history of generating high returns & significant CO_2 free cash flow with minimal acquisitions

CO_2 IRR% 2000-2019

Oil & Gas	18%
Total CO_2 Segment (incl. CO_2 & transport)	28%

SIGNIFICANT CO_2 FREE CASH FLOW

$ millions



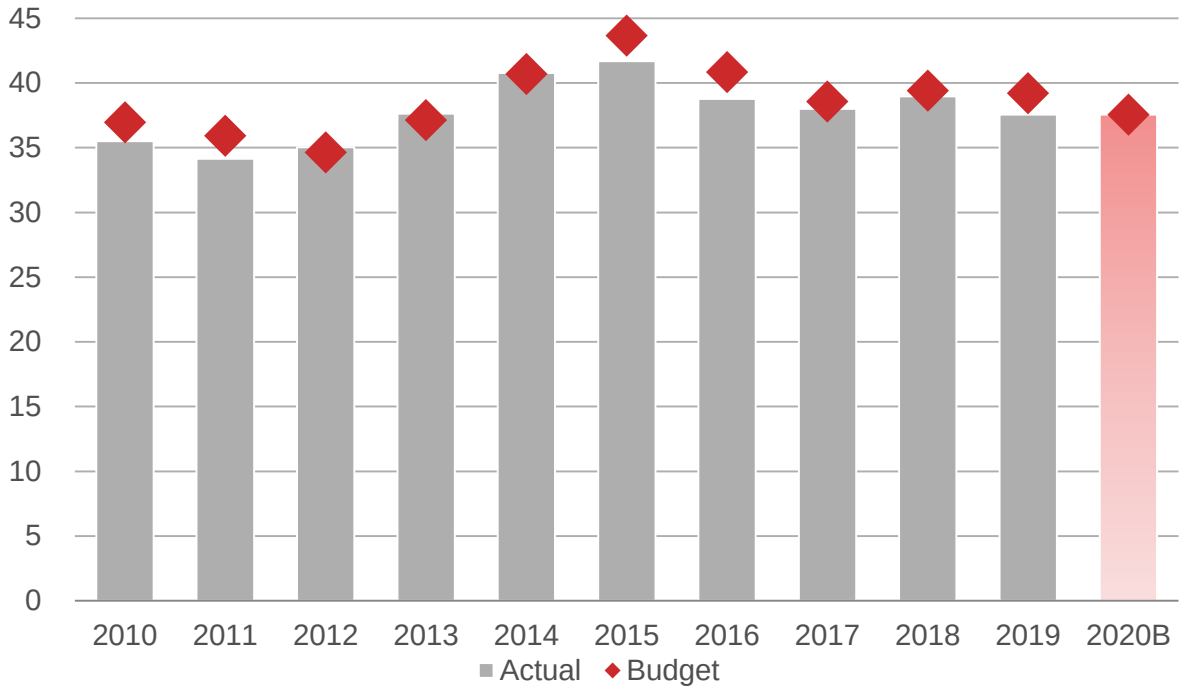
Note: CO_2 Internal Rate of Return (IRR) & CO_2 Free Cash Flow. See Non-GAAP Financial Measures & Reconciliations.

Predictable Oil & Gas Volumes & Managed Commodity Price

Mitigating uncertainties where possible

NET OIL PRODUCTION: ACTUALS VS. BUDGET

mbbld



HEDGED VOLUMES

as of 01/06/2020

	2020	2021	2022	2023
Oil - WTI hedges				
$/bbl	$56.58	$54.21	$54.60	$52.81
bbl/d	29,900	16,100	7,700	4,000
NGLs				
$/bbl	$31.97			
bbl/d	4,544			
Mid-Cush differential				
$/bbl	$0.14			
bbl/d	31,100			

Stable & predictable production over many years with actual oil production within 2% of budget 2010-2019

Disciplined hedge policy mitigates near-term price volatility impact on expected cash flows

Consistently Profitable Operating Margin

Low cash cost structure yields healthy margins despite commodity price cycles

Note: Cash costs & revenue per net oil barrel, including hedges where applicable.

Appendix

Realistic Scenarios Exist

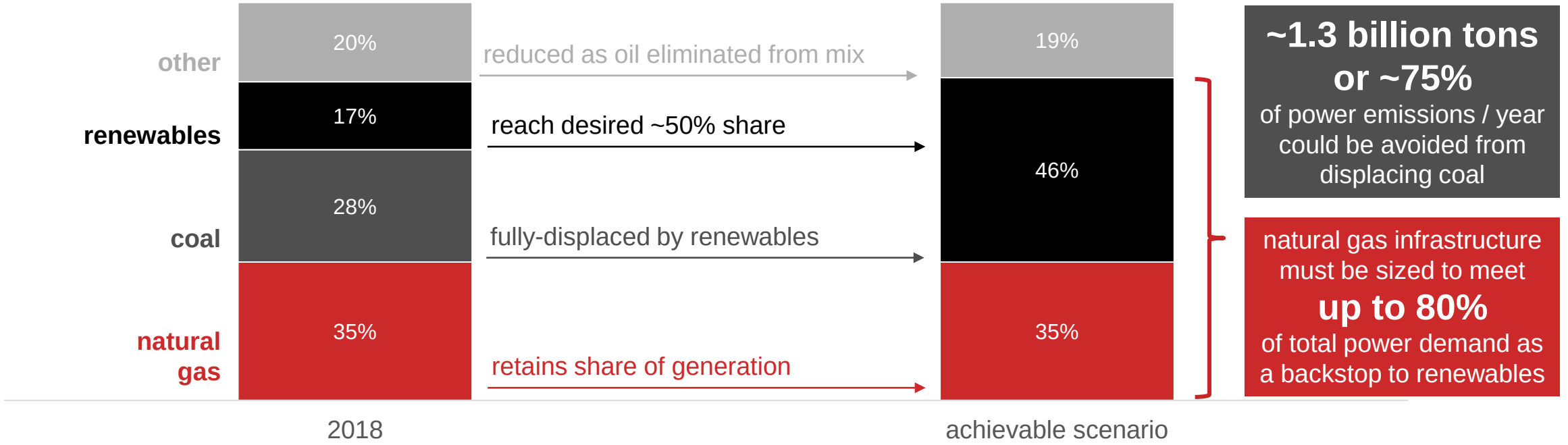
Achieving cost, reliability & emissions objectives

"Wind & solar resources are not consistently available & controllable to serve the energy needs of all customers all the time…the cost of integrating renewable energy is manageable up to ~50 to 60% renewable penetration. At that point, however, the cost of integrating additional renewable energy begins to climb rapidly."

– Utility CEO at U.S. Senate Committee on Energy & Natural Resources (6/4/2019)

SIMPLE EXAMPLE: U.S. POWER MARKET

% based on terawatt-hours



Source: U.S. Energy Information Agency, U.S. National Energy Technology Laboratory, International Energy Agency, World Energy Outlook, November 2019 (Stated Policies Scenario), U.S. EPA Inventory of U.S. Greenhouse Gas Emissions & Sinks 1990-2017 (released in 2019)

Note: Other in electric power generation mix includes nuclear & oil. Oil assumed to go to 0 in achievable future scenario.

Committed to Protecting the Environment

Case studies | Videos available on our website

Maintaining our pipelines' integrity through in-line inspections

Doing business the right way, every day is paramount at Kinder Morgan. We invest millions of dollars each year on integrity management & maintenance programs to protect people & the environment. One of the primary integrity assessment methods we use to help prevent incidents are in-line inspections (ILI).

Our commitment to reducing methane emissions

Kinder Morgan has ~70,000 miles of natural gas pipelines that transport about 40 percent of U.S. natural gas consumed and exported. We are committed to providing natural gas to customers in a safe, reliable & environmentally sound manner. Reducing methane emissions is an important part of our business.

Protecting threatened plant species

We take great care to minimize impacts on the environment where we work & operate. Our plans & procedures are designed to meet or exceed established standards that protect environmentally sensitive areas, such as water bodies, wetlands & endangered species habitats. This includes our efforts to help preserve & protect the Tobusch Fishhook Cactus by collecting these plants within the Gulf Coast Express Pipeline Project right-of-way & providing plants for biodiversity research.

Respecting Indigenous Peoples & Communities

We engage with the communities where we do business, including Indigenous Peoples, which are very important to us. For decades, we have sought to build long-term relationships with Indigenous Peoples through meaningful engagement based on mutual respect.

Prioritizing ESG

Multi-faceted approach to good corporate governance | Ongoing enhancements to disclosures

CORPORATE GOVERNANCE

13 independent out of 16 board members

2 female board members

Majority voting to elect board members annually

Proxy access bylaw provisions

Annual say on pay voting

Director & officer stock ownership guidelines

Compensation linked to ESG factors

Board Environmental, Health & Safety (EHS) committee oversees ESG matters

ESG RESOURCES

Disclosure:

- 2018 ESG Report
- 2ºC scenario analysis included in report
- Annual Meeting Proxy Statement

Framework:

- Operations Management System

Policies & guidelines:

- EHS Policy Statement
- Biodiversity Policy
- Indigenous Peoples Policy
- Community Relations Policy
- Statement on Climate Change
- Corporate Governance Guidelines
- Code of Business Conduct & Ethics
- Contractor Environment / Safety Manual
- Methane Reduction Commitment
- Human Rights Statement

Programs:

- Public Awareness Program
- Kinder Morgan Foundation

Note: For consolidated ESG information, please visit the ESG / sustainability page on our website

Energy Toll Road

Cash flow security with >90% from take-or-pay & other fee-based contracts

2020B EBDA %[a]	Natural Gas Pipelines 61%			Products Pipelines 16%		Terminals 13%			CO_2 10%	
	Interstate / LNG	Intrastate	G&P	Refined products	Crude	Liquids terminals	Jones Act tankers	Bulk terminals	O&G	CO_2 & Transport
Asset Mix[a]	71%	13%	16%	63%	37%	57%	20%	23%	64%	36%
Volume Security	~93% take-or-pay[a]	~76% take-or-pay[a,b]	~82% fee-based with minimum volume requirements and/or acreage dedications[a]	primarily volume-based	~89% fee-based[a]	~80% take-or-pay[a]		primarily minimum volume guarantee or requirements	volume-based	~84% minimum volume committed
Average Remaining Contract Life	6.6 / 20 years	5.7 years[b]	3.0 years	generally not applicable	3.1 years	3.0 years	1.5 years	4.9 years	9 years	
Pricing Security	primarily fixed based on contract	primarily fixed margin	primarily fixed price	annual FERC tariff escalator (PPI-FG + 1.23%)	primarily fixed based on contract	Based on contract; typically fixed or tied to PPI			volumes ~75% hedged[c]	~80% protected by contractual price floors[a]
Regulatory Security	regulated return	essentially market-based	market-based	Pipelines: regulated return Terminals & transmix: not price regulated[d]		Not price regulated			Primarily unregulated	
Commodity Price Exposure	no direct exposure	limited exposure	limited exposure	Minimal, limited to transmix business		No direct exposure			Full-year 2020: ~$3mm in DCF per $1/Bbl change in WTI	

Note: All figures as of 1/1/2020, unless otherwise noted.

a) Based on 2020 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

b) Includes term sale portfolio.

c) Percentage of FY2020 budgeted net crude oil, propane & heavy NGL (C4+) net equity production.

d) Products terminals not FERC regulated, except portion of CALNEV.

Joint Venture Treatment in Key Metrics

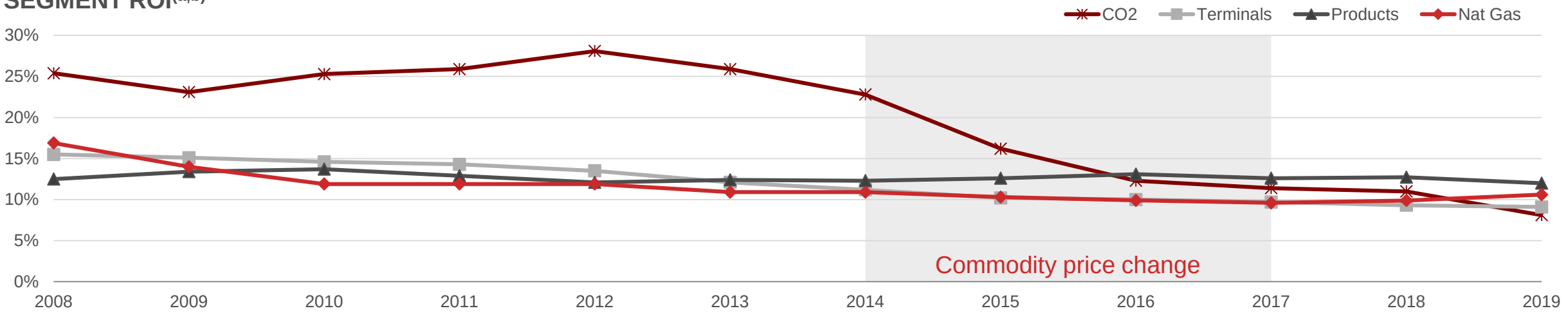
	KM controls & fully consolidates third party portion referred to as noncontrolling interests in financial statements	**KM does not control or consolidate** KM portion referred to as equity investments in financial statements
Example JVs	Elba Liquefaction (51%), BOSTCO (55%)	NGPL (50%), SNG (50%), FGT (50%), MEP (50%), FEP (50%), Gulf LNG (50%)
Net Income	**Includes 100% of JV Net Income** consolidated throughout income statement line items	**Includes KM share of JV Net Income** included in Earnings from Equity Investments
Net Income Available to Common Stockholders	**Includes KM share of JV Net Income** excludes Net Income Attributable to Noncontrolling Interests	**Includes KM share of JV Net Income** included in Earnings from Equity Investments
Segment EBDA	**Includes 100% of JV's operating results before DD&A** excludes G&A & corporate charges, interest expense & book taxes	**Includes KM share of JV Net Income** includes JV DD&A, G&A & interest expenses & book taxes, if any
Adjusted EBITDA	**Includes KM share of JV's (Net Income + DD&A + Book Taxes + Interest Expense)** excludes Net Income Attributable to Noncontrolling Interests	**Includes KM share of JV's (Net Income + DD&A + Book Taxes)** i.e., after subtracting interest expense
Distributable Cash Flow (DCF)	**Includes KM share of JV's (Net Income + DD&A + Book Taxes – Cash Taxes – Sustaining CapEx)** excludes Net Income Attributable to Noncontrolling Interests	**Includes KM share of JV's (Net Income + DD&A + Book Taxes – Cash Taxes – Sustaining CapEx)**
Debt	**100% of JV debt included, if any** fully consolidated on balance sheet	**No JV debt included** JV's Adjusted EBITDA contribution is after subtracting interest expense
Sustaining Capital	**Includes KM owned % of JV sustaining capital**	
Discretionary Capital	**Includes KM contributions to JVs based on % owned, including for projects & debt repayment**	

Note: See Non-GAAP Financial Measures & Reconciliations.

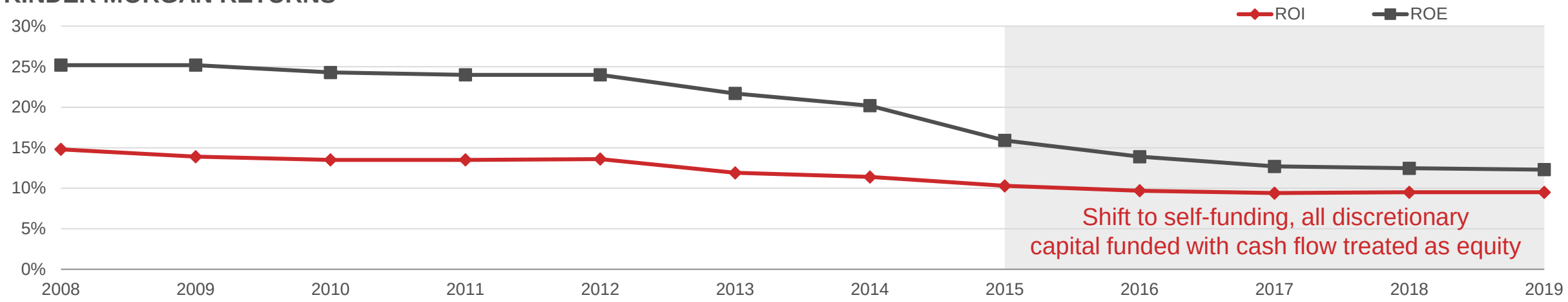
Returns on Invested Capital

Targeted returns for new capital investment are substantially above cost of capital

SEGMENT ROI[(a,b)]



KINDER MORGAN RETURNS



Notes: See Non-GAAP Financial Measures & Reconciliations. Reflects KMP (2000-2012), KMP & EPB (2013-2014) & KMI (2015-2019).

a) G&A is deducted to calculate the combined Return on Investment, but is not allocated to the segments & therefore not deducted to calculate the individual Segment ROI.

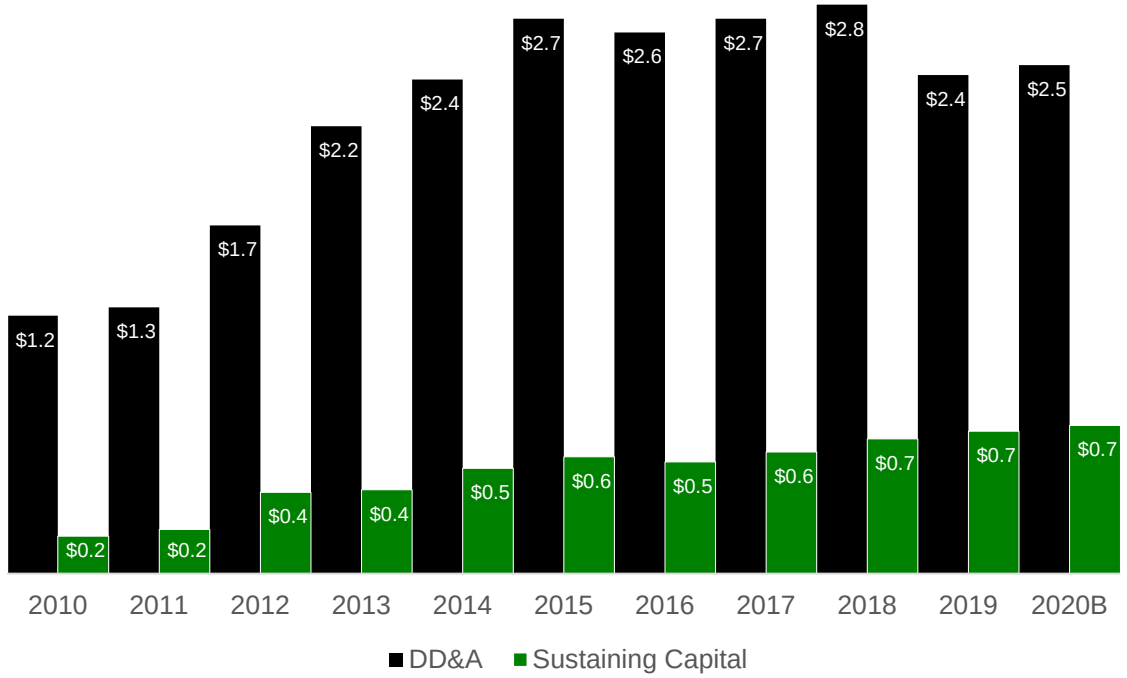
b) Natural Gas segment ROI includes NGPL & Citrus investments since 2015.

Distributable Cash Flow (DCF) versus Net Income

Largest differences easily explainable & reflective of cash earnings

DEPRECIATION EXPENSE VS. SUSTAINING CAPEX[(a)]

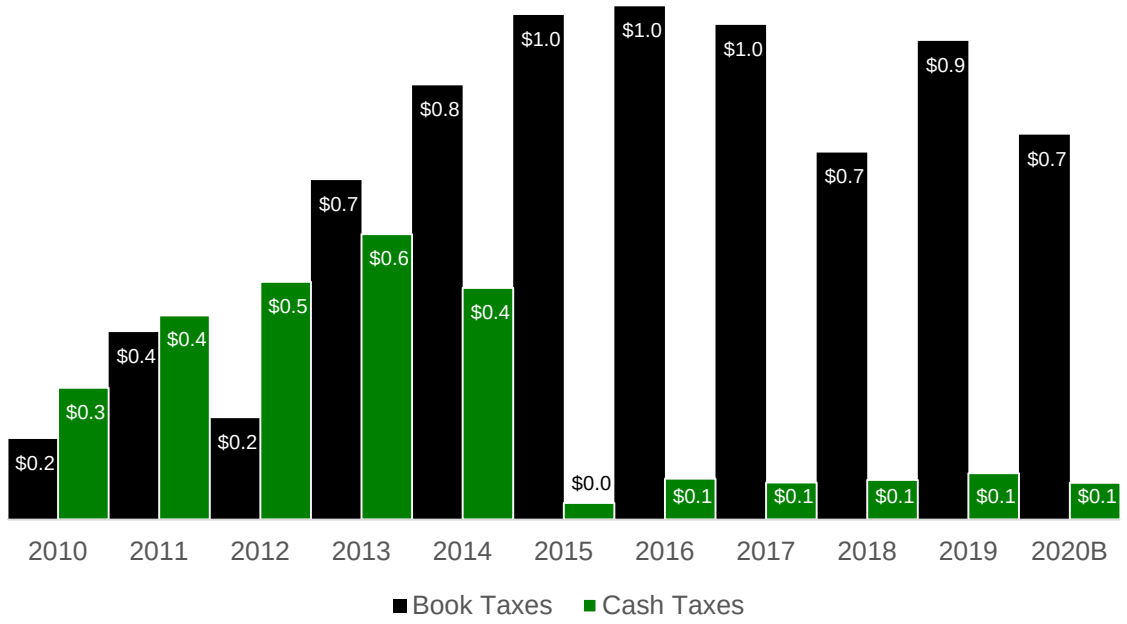
$ billions



- Our sustaining capex budget is built bottoms up by operations based on need & long-term plans
- Exemplary safety record demonstrates our spending level on sustaining capex is appropriate

BOOK TAX EXPENSE VS. CASH TAXES

$ billions



- We do not expect to be a significant U.S. cash tax payer until beyond 2026

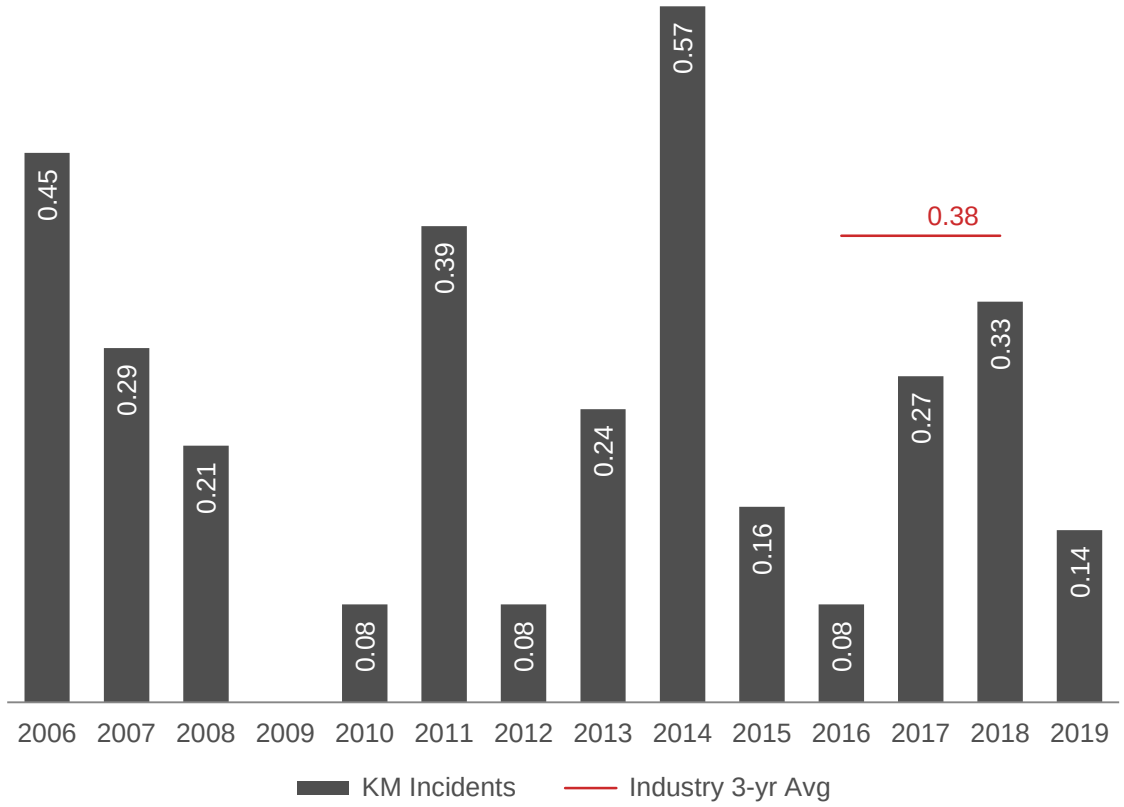
Note: 2010-2018 as presented on the distributable cash flow reconciliation to net income available to common stockholders in SEC Annual Forms 10-K, which includes KM's share of unconsolidated JV amounts.

a) Represents depletion, depreciation & amortization expense (DD&A), including amortization of excess cost of equity investments & JV DD&A. See Non-GAAP Financial Measures & Reconciliations.

Incidents & Releases: Liquids Pipelines

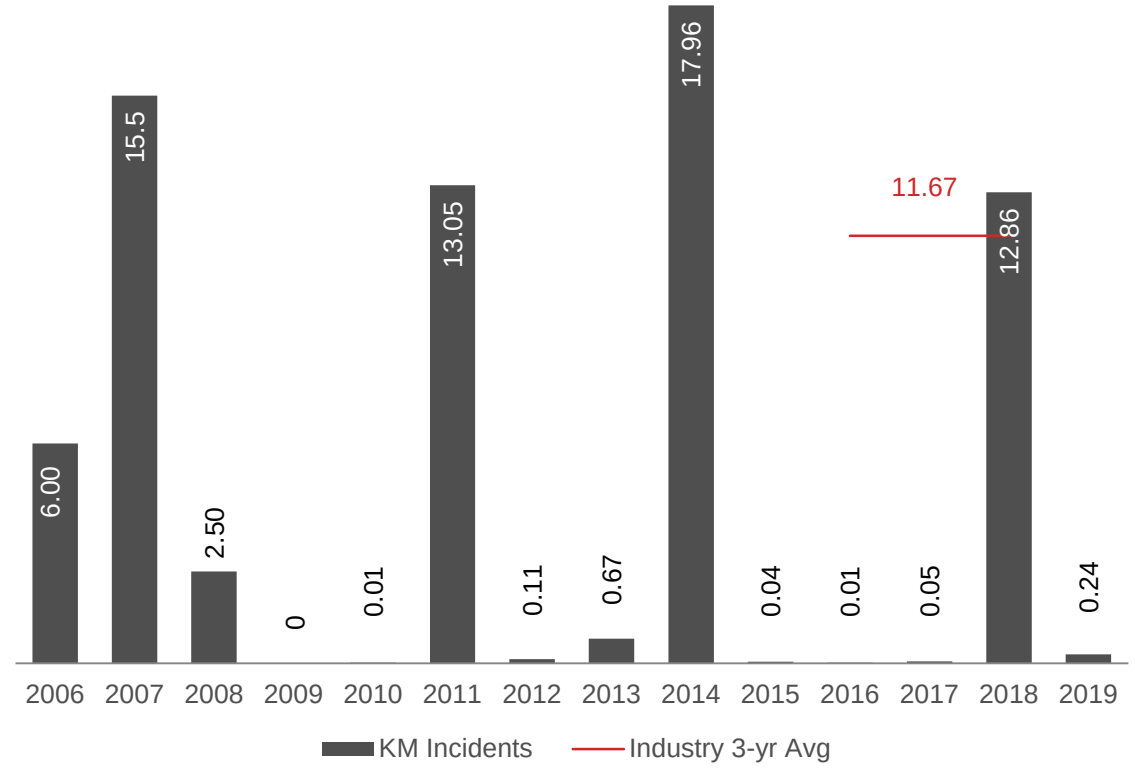
Liquids pipeline right-of-way

INCIDENTS PER 1,000 MILES[a,b]



RELEASE RATE[a,b]

Barrels per billion barrel miles



Note: KM totals exclude non-DOT jurisdictional CO_2 Gathering & Crude Gathering for compatibility with industry comparisons.

a) Failures involving onshore pipelines that occurred on the ROW, including valve sites, in which there is a release of the liquid or carbon dioxide transported resulting in any of the following:
   - Explosion or fire not intentionally set by the operator
   - Release 5 barrels or greater.
   - Death of any person
   - Personal injury necessitating hospitalization
   - Estimated property damage, including cost of clean-up & recovery, value of lost product & damage to the property of the operator or others, or both, exceeding $50,000; not included: natural gas transportation assets

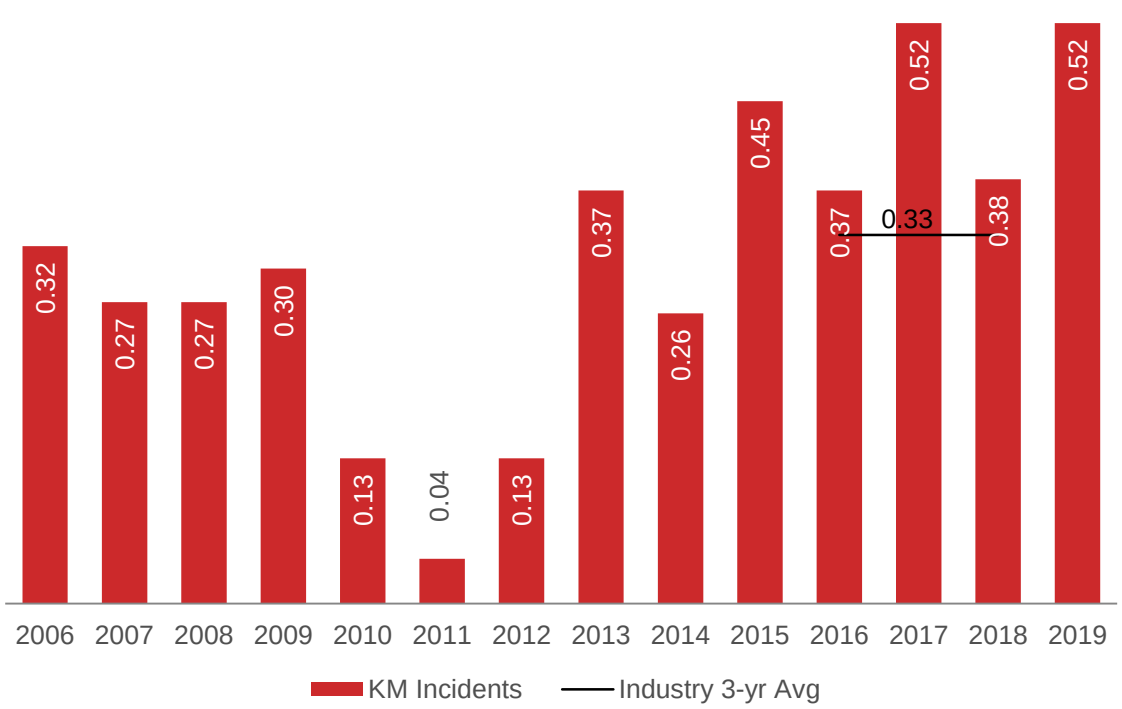
b) 2016-2018 most recent PHMSA 3-year average available.

Incidents & Releases: Natural Gas Pipelines

Natural gas pipeline right-of-way

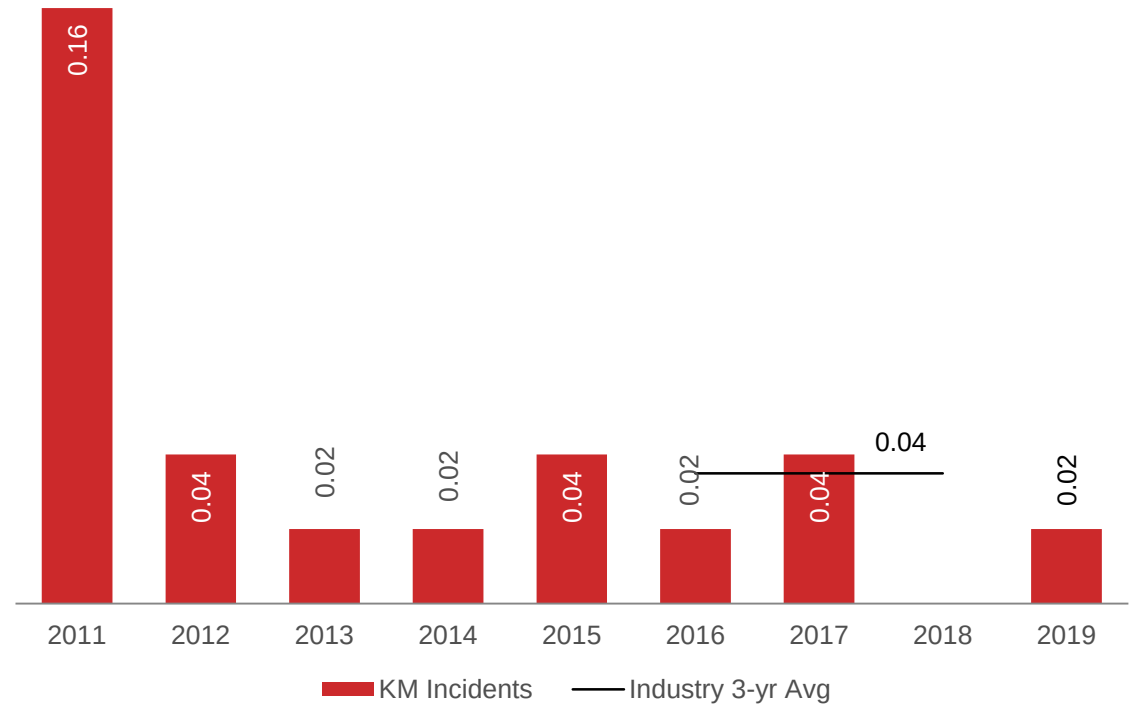
INCIDENTS RATE ALL REPORTABLE INCIDENTS[a,b]

Incidents per 1,000 miles



INCIDENTS RATE ONSHORE RUPTURES ONLY[b,c,d]

Incidents per 1,000 miles



a) Excludes El Paso & Copano assets in periods prior to acquisition (El Paso 5/25/2012, Copano 5/1/2013). An Incident means any of the following events:
   - An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility & that results in one or more of the following consequences:
     - A death or personal injury necessitating in-patient hospitalization; or
     - Estimated property damage of $50,000 or more, including loss to the operator & others, but excluding cost of gas lost (2010 & earlier rates include cost of gas lost)
     - Unintentional estimated gas loss of 3 million cubic feet or more
   - An event that results in an emergency shutdown of an LNG facility
   - An event that is significant, in the judgment of the operator, even though it did not meet the criteria above

b) 2016-2018 most recent PHMSA 3-year average available.

c) Rupture defined as a break, burst, or failure that exposes a visible pipeline fracture surface. Kinder Morgan rupture rates calculated using most current pipeline mileage. Industry rate excludes Kinder Morgan data.

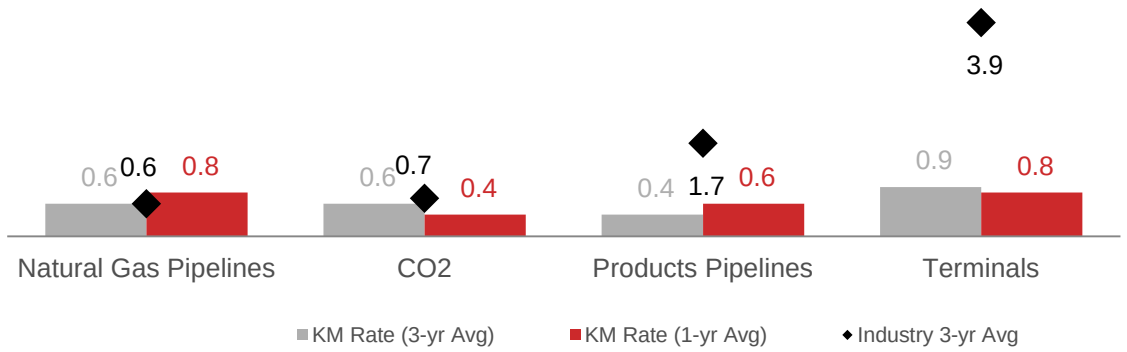
d) All Kinder Morgan ruptures occurred on legacy El Paso facilities prior to the Kinder Morgan acquisition.

Employee Safety Statistics

12-month performance summary as of 12/31/2019

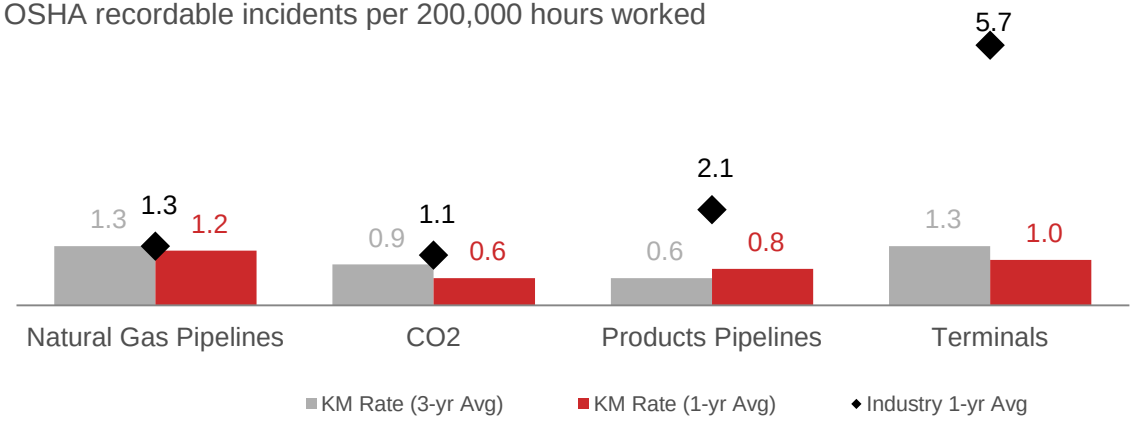
DAYS AWAY, RESTRICTED, OR TRANSFERRED (DART) RATE

Days Away, Restricted or Transferred incidents per 200,000 hours worked



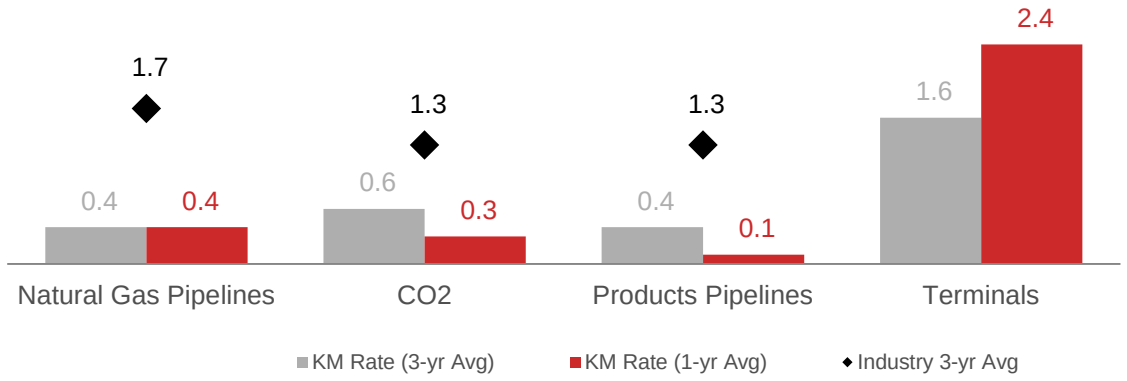
OSHA TOTAL RECORDABLE INCIDENT RATE (TRIR)

OSHA recordable incidents per 200,000 hours worked



VEHICLE INCIDENT RATE[(a)]

Avoidable vehicle accidents per 1,000,000 miles



a) Industry average not available for Terminals.

Non-GAAP Financial Measures & Reconciliations

Defined Terms

Reconciliations for the historical periods

Use of Non-GAAP Financial Measures

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

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

We do not provide (i) budgeted net income available to common stockholders and net income (the GAAP financial measures most directly comparable to budgeted DCF and Adjusted EBITDA, respectively) or budgeted metrics derived therefrom (such as the portion of net income attributable to an individual capital project, the GAAP financial measure most directly comparable to Project EBITDA) due to the impracticality of predicting certain amounts required by GAAP, such as unrealized gains and losses on derivatives marked to market, and potential changes in estimates for certain contingent liabilities; (ii) budgeted revenue (the GAAP financial measure closest to net revenue) due to impracticality of predicting certain items required by GAAP, including projected commodity prices at the multiple purchase and sale points across certain intrastate pipeline systems. Instead, we are able to project the net revenue received for transportation services based on contractual agreements and historical operational experience; or (iii) budgeted CO_2 Segment EBDA (the GAAP financial measure most directly comparable to 2020 budgeted CO_2 Free Cash Flow) due to the inherent difficulty and impracticability of predicting certain amounts required by GAAP, such as potential changes in estimates for certain contingent liabilities and unrealized gains and losses on derivatives marked to market.

Certain Items, as adjustments used to calculate our non-GAAP measures, are items that are required by GAAP to be reflected in net income, but typically either (1) do not have a cash impact (for example, asset impairments), or (2) by their nature are separately identifiable from our normal business operations and in our view are likely to occur only sporadically (for example, certain legal settlements, enactment of new tax legislation and casualty losses).

JV DD&A is calculated as (i) KMI's share of DD&A from unconsolidated JVs, reduced by (ii) our partners' share of DD&A from JVs consolidated by KMI.

JV Sustaining Capex is calculated as KMI's share of sustaining capex made by joint ventures (both unconsolidated JVs and JVs consolidated by KMI).

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

DCF is calculated by adjusting net income available to common stockholders for Certain Items (or Adjusted Earnings, as defined above), and further by DD&A and amortization of excess cost of equity investments, income tax expense, cash taxes, sustaining capital expenditures and other items. DCF is a significant performance measure useful to management and external users of our financial statements in evaluating our performance and in measuring and estimating the ability of our assets to generate cash earnings after servicing our debt, paying cash taxes and expending sustaining capital, that could be used for discretionary purposes such as common stock dividends, stock repurchases, retirement of debt, or expansion capital expenditures. DCF should not be used as an alternative to net cash provided by operating activities computed under GAAP. We believe the GAAP measure most directly comparable to DCF is net income available to common stockholders. DCF per common share is DCF divided by average outstanding common shares, including restricted stock awards that participate in common dividends

Use of Non-GAAP Financial Measures (Continued)

Adjusted Segment EBDA is calculated by adjusting segment earnings before DD&A and amortization of excess cost of equity investments (Segment EBDA) for Certain Items attributable to the segment. Adjusted Segment EBDA is used by management in its analysis of segment performance and management of our business. General and administrative expenses and certain corporate charges are generally not under the control of our segment operating managers, and therefore, are not included when we measure business segment operating performance. We believe Adjusted Segment EBDA is a useful performance metric because it provides management and external users of our financial statements additional insight into the ability of our segments to generate segment cash earnings on an ongoing basis. We believe it is useful to investors because it is a measure that management uses to allocate resources to our segments and assess each segment's performance. We believe the GAAP measure most directly comparable to Adjusted Segment EBDA is Segment EBDA.

Adjusted EBITDA is calculated by adjusting net income before interest expense, income taxes, and DD&A, including amortization of excess cost of equity investments (EBITDA) for Certain Items, KMI's share of unconsolidated joint venture (JV) DD&A and income tax expense (net of our partners' share of consolidating JV DD&A and income tax expense), and net income attributable to noncontrolling interests other than KML noncontrolling interests (sold on December 15, 2019). Adjusted EBITDA is used by management and external users, in conjunction with our Net Debt (as described further below), to evaluate certain leverage metrics. Therefore, we believe Adjusted EBITDA is useful to investors. We believe the GAAP measure most directly comparable to Adjusted EBITDA is net income.

Net Debt is calculated by subtracting from debt (i) cash and cash equivalents, (ii) the preferred interest in the general partner of Kinder Morgan Energy Partners L.P. (repaid on January 15, 2020), (iii) debt fair value adjustments, (iv) the foreign exchange impact on Euro-denominated bonds for which we have entered into currency swaps and (v) 50% of the outstanding KML preferred equity. Management believes Net Debt is useful to investors and other users of our financial information in evaluating our leverage. We believe the most comparable measure to Net Debt is debt net of cash and cash equivalents.

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, our percentage share of the foregoing. Management uses Project EBITDA to evaluate our return on investment for capital projects before expenses that are generally not controllable by operating managers in our business segments. We believe the GAAP measure most directly comparable to Project EBITDA is the portion of net income attributable to a capital project.

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

CO_2 Internal Rate of Return (IRR) is the actual rate of return on the CO_2 segment, and its EOR oil production assets and investments. The CO_2 IRR is calculated based on each year's CO_2 Free Cash Flows for the years from 2000 to 2019. Management uses CO_2 IRR in conjunction with CO_2 Free Cash Flow to evaluate our return on investments made in our CO_2 segment.

Unconsolidated joint ventures accounted for as equity method investments include: Citrus Corporation (Citrus), Southern Natural Gas Company, LLC, NGPL Holdings LLC, Gulf Coast Express Pipeline LLC, Midcontinent Express Pipeline Company LLC, Gulf LNG Holdings Group, LLC, Plantation Pipeline Company, Kinder Morgan Utopia Holdco LLC, Permian Highway Pipeline LLC, EagleHawk Field Services LLC, Watco Companies, LLC, Ruby Pipeline Holding Company, L.L.C., Cortez Pipeline Company and others.

GAAP Reconciliations

$ in millions

Reconciliation of DCF	2019
Net income available to common stockholders (GAAP)	$ 2,190
Total Certain Items	(29)
Adjusted Earnings[a]	2,161
DD&A and amortization of excess cost of equity investments for DCF[b]	2,867
Income tax expense for DCF[a,b]	714
Cash taxes[c]	(90)
Sustaining capital expenditures[c]	(688)
Other items[d]	29
DCF	$ 4,993

Reconciliation of Net Debt	
Outstanding long-term debt	$ 30,883
Current portion of debt	2,377
Foreign exchange impact on hedges for Euro Debt outstanding	(44)
Less: cash & cash equivalents	(185)
Net Debt	$ 33,031

Reconciliation of Adjusted EBITDA	2019
Net income (GAAP)	$ 2,239
Total Certain Items	(29)
DD&A and amortization of excess cost of equity investments	2,494
Income tax expense[a]	627
KMI's share of JV DD&A and income tax expense[a,e]	487
Interest, net[a]	1,816
Net income attributable to NCI (net of KML NCI)[a]	(16)
Adjusted EBITDA	$ 7,618

Certain Items	
Fair value amortization	$ (29)
Legal, environmental and taxes other than income tax reserves	46
Change in fair market value of derivative contracts[f]	(24)
Gain on divestitures and impairments, net[g]	(280)
Income tax Certain Items	299
NCI associated with Certain Items	(4)
Other	(37)
Total Certain Items	$ (29)

a) Amounts are adjusted for Certain Items.
b) Includes KMI's share of DD&A or income tax expense from JVs, net of DD&A or income tax expense attributable to KML NCI, as applicable.
c) Includes KMI's share of cash taxes or sustaining capital expenditures from JVs, as applicable.
d) Includes non-cash pension expense, net of cash contributions, and non-cash compensation associated with our restricted stock program.
e) KMI's share of unconsolidated JV DD&A and income tax expense, net of consolidating JV partners' share of DD&A.
f) Gains or losses are reflected in our DCF when realized.
g) Includes: (i) a $1,296 million pre-tax gain on the sale of KML and U.S. Cochin Pipeline and a pre-tax loss of $364 million for asset impairments, related to gathering and processing assets in Oklahoma and northern Texas in our Natural Gas Pipelines business segment and oil and gas producing assets in our CO2 business segment; and (ii) a pre-tax $650 million loss for an impairment of our investment in Ruby Pipeline.

GAAP Reconciliations

$ in millions

Reconciliation of Adjusted Segment EBDA	2019
Natural Gas Pipelines (GAAP)	$ 4,661
Certain Items	(51)
Natural Gas Pipelines Adjusted Segment EBDA	4,610
Products Pipelines (GAAP)	1,225
Certain Items	33
Products Pipelines Adjusted Segment EBDA	1,258
Terminals (GAAP)	1,506
Certain Items	(332)
Terminals Adjusted Segment EBDA	1,174
CO_2 (GAAP)	681
Certain Items	26
CO_2 Adjusted Segment EBDA	707
Kinder Morgan Canada (GAAP)	(2)
Certain Items	2
Kinder Morgan Canada Adjusted Segment EBDA	-
Total Segment EBDA (GAAP)	8,071
Total Segment EBDA Certain Items	(322)
Total Adjusted Segment EBDA	$ 7,749

Reconciliation of DD&A and amortization of excess cost of equity investments for DCF	
Depreciation, depletion and amortization (GAAP)	$ (2,411)
Amortization of excess cost of equity investments (GAAP)	(83)
DD&A and amortization of excess cost of equity investments	(2,494)
KMI's share of JV DD&A	(392)
DD&A attributable to KML NCI	19
DD&A and amortization of excess cost of equity investments for DCF	$ (2,867)

Reconciliation of general and administrative and corporate charges	
General and administrative (GAAP)	$ (590)
Corporate benefit (charges)	(21)
Certain Items	13
General and administrative and corporate charges[(a)]	$ (598)

Reconciliation of interest, net	2019
Interest, net (GAAP)	$ (1,801)
Certain Items	(15)
Interest, net[(a)]	$ (1,816)

Reconciliation of income tax expense for DCF[(a)]	
Income tax expense (GAAP)	$ (926)
Certain Items	299
Income tax expense[(a)]	(627)
KMI's share of taxable JV income tax expense[(a)]	(95)
Income tax expense attributable to KML NCI[(a)]	8
Income tax expense for DCF[(a)]	$ (714)

Reconciliation of KML NCI DCF adjustments[(a)]	
Net income attributable to KML NCI	$ (29)
KML NCI associated with Certain Items	(4)
KML NCI[(a)]	(33)
DD&A attributable to KML NCI	(19)
Income tax expense attributable to KML NCI[(a)]	(8)
KML NCI DCF adjustments[(a)]	$ (60)

Reconciliation of net income attributable to NCI (net of KML NCI and Certain Items)	
Net income attributable to NCI (GAAP)	$ (49)
Less: KML NCI[(a)]	(33)
Net income attributable to NCI (net of KML NCI[(a)])	(16)
NCI associated with Certain Items	(4)
Net income attributable to NCI (net of KML NCI and Certain Items)	$ (20)

a) Amounts are adjusted for Certain Items.

Explanation of Return Calculations

	Formula	Notes
Segment Return on Investment	Adjusted Segment EBDA less sustaining capex	(a)
	Average Total Investment	(b)
Return on Investment	DCF before interest	(c)
	Average Total Investment	(b)
Return on Equity	DCF (after interest)	(d)
	Average equity	(e)

	Formula	Notes
Calculation of Total Investment:	Gross PP&E	
	Equity Investments (JVs)	(f)
	Goodwill	
	Gross intangibles (excluding amortization)	
	Plus:	
	Asset write-offs / retirements	
	Cumulative environmental reserves	
	Legal reserves / expenditures	(g)
	Cumulative cash spent on asset retirement	(h)
	Minus:	
	Cumulative sustaining capex	
	Assumed liabilities	
	Common control adjustment	(i)
	Cumulative asset retirement costs	(h)
	Proceeds from sold assets / investments	
	Equals:	
	Total Investment	(j)

a) Adjustments are made to Segment EBDA to more closely tie to cash: (1) our share of JV DD&A is added back and our share of JV sustaining capex is deducted, (2) Express and Endeavor (1H 2014 and prior) pre-tax earnings are subtracted and cash received is added back. Reflects KMP segments (2000-2012), KMP and EPB segments (2013 and 2014) and KMI segments (2015 and after).
b) Total Investment reflects the trailing 5 quarter average.
c) For all years prior to 2015 (prior to the KMI acquisition of KMP, KMR and EPB), this item is defined as the sum of the individual Adjusted Segment EBDA less sustaining capex and G&A. Thereafter, this item is defined as the sum of the individual Adjusted Segment EBDA less sustaining capex, less G&A and cash taxes, plus book taxes deducted at the segment level. Book and cash taxes include KMI's share of unconsolidated C-corp JVs. KML contributions are shown at 100% interest prior to December 2019 sale.
d) For all years prior to 2015 (prior to the KMI acquisition of KMP, KMR and EPB), DCF is defined as limited partners' pretax income before Certain Items and DD&A, less cash taxes paid and sustaining capital expenditures for KMP and EPB, plus KMP's and EPB's share of JV DD&A less KMP's and EPB's share of JV sustaining capital expenditures, less equity earnings plus cash distributions received for Express and Endeavor (1H 2014 and prior), plus the general partner's incentive and the general partner non-controlling interest, as applicable. For 2015 and after, DCF is shown and reconciled in the Appendix: GAAP Reconciliation in this or prior year presentations.
e) Prior to 2016, equity is based on cumulative equity raised inception to date as of each quarter end and then averaged for the year. 2016 and after also include DCF spent to fund growth capital (excluding KML growth capital after its IPO).
f) Investments are generally calculated based on cumulative contributions and are not increased for earnings or decreased for distributions.
g) Litigation and environmental reserves deducted as Certain Items are added to investment, except for SFPP and CALNEV litigation reserves. For those pipelines, actual legal payments are added to the investment when they are made.
h) For GAAP purposes, the present value of accumulated asset retirement costs are included in gross PP&E; for purposes of this calculation, we decrease our Total Investment / subtract out the accumulated asset retirement costs, and increase our Total Investment / add back any cash actually spent on asset retirement.
i) For assets acquired from Kinder Morgan, Inc. (for example Express, Trans Mountain, TGP and EPNG) or El Paso, Inc. by either KMP or EPB (the MLPs) which represent a transfer of assets between entities under common control and were recorded for financial statement purposes at KMI's carrying value, an adjustment has been made to reflect these assets at the MLPs' purchase price.
j) Through 2019, for Canadian assets / investments, Total Investment is based on acquisition price plus cumulative expansion capital including overhead. The purpose of calculating Total Investment in this manner is to exclude the foreign exchange impact reflected in our GAAP financials which revalue the entire asset balance based on the end of period exchange rate. KML IPO & Divestiture proceeds are deducted as of December 2019.

Reconciliation of CO_2 Free Cash Flow

$ in millions

Reconciliation of CO2 Free Cash Flow	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Segment EBDA	$ 965	$ 1,099	$ 1,322	$ 1,435	$ 1,240	$ 657	$ 827	$ 847	$ 759	$ 681
Certain items:										
Non-cash impairments and project write-offs	-	-	-	-	243	622	29	-	79	75
Derivatives and other	(5)	(5)	4	(3)	(25)	(138)	63	40	90	(49)
Severance tax refund									(21)	
Adjusted Segment EBDA	960	1,094	1,326	1,432	1,458	1,141	919	887	907	707
Capital expenditures (a)	373	433	453	667	792	725	276	436	397	349
Acquisitions	-	-	14	286	-	-	-	-	21	-
CO2 Free Cash Flow	**$ 587**	**$ 661**	**$ 858**	**$ 479**	**$ 666**	**$ 416**	**$ 643**	**$ 451**	**$ 489**	**$ 358**

a) Includes both sustaining & discretionary capital expenditures.