



The Best is Yet to Come

January 25, 2017

Forward-Looking Statements / Non-GAAP Financial Measures

This presentation includes forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 and Section 21E of the Securities and Exchange Act of 1934. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. In particular, statements, express or implied, concerning future actions, conditions or events, future operating results or the ability to generate revenues, income or cash flow or to pay dividends are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations of Kinder Morgan, Inc. may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond Kinder Morgan's 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 and regulatory conditions and developments; the timing and success of business development efforts; technological developments; condition of capital and credit markets; inflation rates; interest rates; the political and economic stability of oil producing nations; energy markets; weather conditions; environmental conditions; business, regulatory and legal decisions; terrorism, including cyber-attacks; and other uncertainties. There is no assurance that any of the actions, events or results of the forward-looking statements will occur, or if any of them do, what impact they will have on our results of operations or financial condition. Because of these uncertainties, you are cautioned not to put undue reliance on any forward-looking statement. Please read "Risk Factors" and "Information Regarding Forward-Looking Statements" in our most recent Annual Report on Form 10-K and our subsequently filed Exchange Act reports, which are available through the SEC's EDGAR system at www.sec.gov and on our website at www.kindermorgan.com.

We use non-generally accepted accounting principles ("non-GAAP") financial measures in this presentation. Our reconciliation of non-GAAP financial measures to comparable GAAP measures can be found in the Appendix to this presentation. These non-GAAP measures should not be considered as alternatives to GAAP financial measures.

Kinder Morgan Investor Conference

8:00	-	8:20	Vision – Rich Kinder
8:20	-	9:30	Operational Excellence – Steve Kean
9:30	-	9:45	Break
9:45	-	10:30	Financial Excellence – Kimberly Dang
10:30	-	11:30	Q&A

Vision

Rich Kinder

Executive Chairman

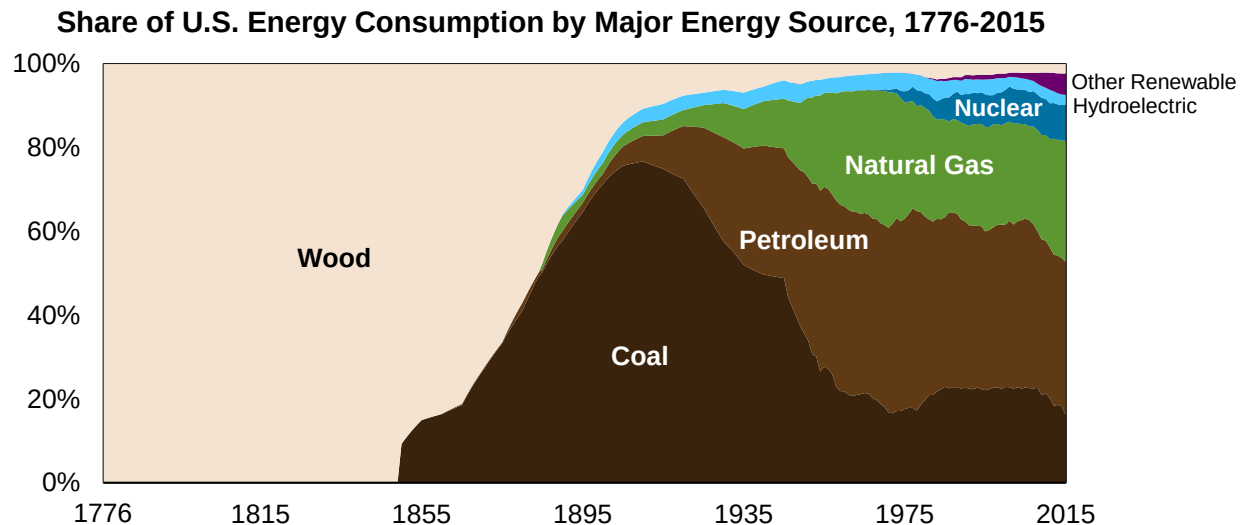
The Importance of Fossil Fuels

■ Our way of life would be impossible without fossil fuels

- Widespread use of coal, oil and natural gas began during the Industrial Revolution, replacing wood as the primary energy source in the U.S.
- With fossil fuels, quality of life and productivity has significantly improved
 - Fossil fuels have driven the development of long-distance transportation, access to fresh food year-round, improved medicine and health care, increased productivity via vehicles and equipment, development of plastics and other modern goods, etc.
- No other energy source is an economically viable and reliable substitute today

■ Fueling America's growth for over a century

- While the mix of fuel has changed, fossil fuels have accounted for over 80% of total U.S. energy consumption for more than 100 years



Fuels Our Daily Essentials

Electricity and Transportation...

■ Electricity

- Fossil fuels generated ~67% of U.S. electricity in 2015 (~66% for 1st 9 months of 2016)^(a)
- Despite decades of R&D and subsidies, renewables only accounted for ~13% of generation in 2015 (~15% for 1st 9 months of 2016); about half is hydropower which is not expected to grow^(a)
- The power grid needs reliable sources of fuel to meet variable-load demand
- Solar and wind are intermittent while natural gas can be stored and dispatched as needed
- Without substantial breakthroughs in battery technology, solar and wind require reliable backup power generation sources
 - It would take ~6 million Tesla Powerwall 2 batteries (about \$30 billion) to equal one day of energy supplied by **just one** of Kinder Morgan's natural gas storage fields^(b)
 - As solar and wind power increases, the need for fast-starting, reliable natural gas-powered generation as a backstop and load smoother increases concurrently

■ Transportation

- Over 99% of U.S. light vehicles today run on gasoline or diesel (>250 million cars and trucks)^(c)
- Electric vehicles (EVs) are still relatively expensive, have limited driving ranges and supporting infrastructure is not well-developed
 - Given range anxiety and projections that EVs will remain relatively expensive for the foreseeable future, EVs are expected to account for only ~2% of U.S. vehicles in operation by 2025^(c)
 - Also, EVs are a potential source of demand for natural gas; incremental power demand from EVs could equate to almost 2 Bcf/d of natural gas by 2035^(d)

(a) EIA, Monthly Energy Review, December 2016.

(b) Tesla website and KMI internal calculations. Assumes 0.7 Bcf/d natural gas storage withdrawal capacity, equivalent to our West Clear Lake facility.

(c) Goldman Sachs, Start Me Up v2.0, November 2016.

(d) Wood Mackenzie, Tesla Model 3: Does it signal an Electric Car Revolution?, May 2016, based on "Increased Adoption – Medium" case.

Fuels Our Daily Essentials

... and Much, Much More

■ Clothing

- Approximately 66% of global textile production comes from synthetic fibers derived from fossil fuels^(a)
- The extensive use of synthetic fibers has improved the affordability and durability of clothes
- Even the production of cotton (28% of textile production)^(a) depends heavily on fossil fuels for fertilizing, irrigating and harvesting the material as well as manufacturing and distributing the final product

■ Plastics and petrochemicals

- Everything “plastic” originates from petroleum or natural gas
- Petrochemical crackers use natural gas and petroleum feedstocks to produce the basic building blocks for making chemicals and plastics

■ Agriculture

- Diesel and natural gas fuels tilling, planting and harvesting
- Natural gas is the key feedstock for fertilizers and pesticides to enhance soil fertility and to protect against pests and weeds

■ Technology, medicine, chemicals, steel, asphalt, construction materials, etc...

(a) Textile Exchange, Preferred Fiber and Materials Market Report, July 2016.

Natural Gas Critical to Climate Goals

- Natural gas is the cleanest burning fossil fuel with significantly lower emissions than coal or fuel oil
- Switching from coal to natural gas has driven a reduction in the nation's power sector CO₂ emissions
 - 2015 U.S. power sector CO₂ emissions were the lowest since 1993 despite a 28% increase in overall power generation^(a)
 - 2015 U.S. power sector CO₂ emissions were ~21% lower than 2007 emissions^(a)
- U.S. methane emissions decreased 6% from 1990 to 2014^(b) despite a 46% increase in natural gas production^(a) over the same period

Monthly Energy Review ^(a)	1993	2007	2015
U.S. Population	~260 million	~301 million	~321 million
Real GDP	~\$9.5 trillion	~\$14.9 trillion	~\$16.3 trillion
Power sector CO ₂ emissions	1.92 GT	2.42 GT	1.91 GT
Power generation (GWh)	3,197,191	4,156,745	4,077,601
Coal	53%	49%	33%
Natural Gas	13%	22%	33%
Nuclear	19%	19%	20%
Solar/Wind	<1%	<1%	5%

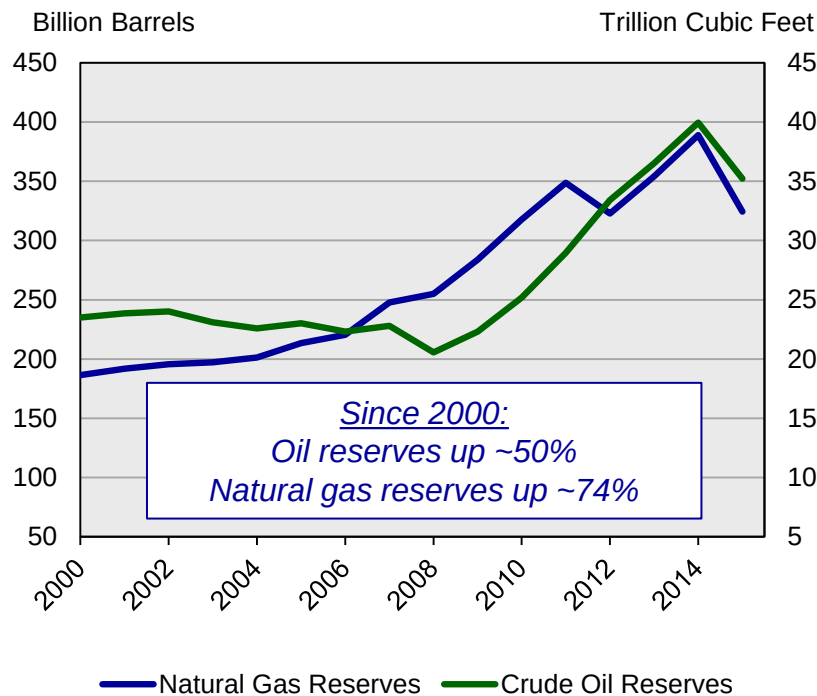
(a) EIA, Monthly Energy Review, December 2016.

(b) EPA, U.S. Greenhouse Gas Inventory Report, April 2016.

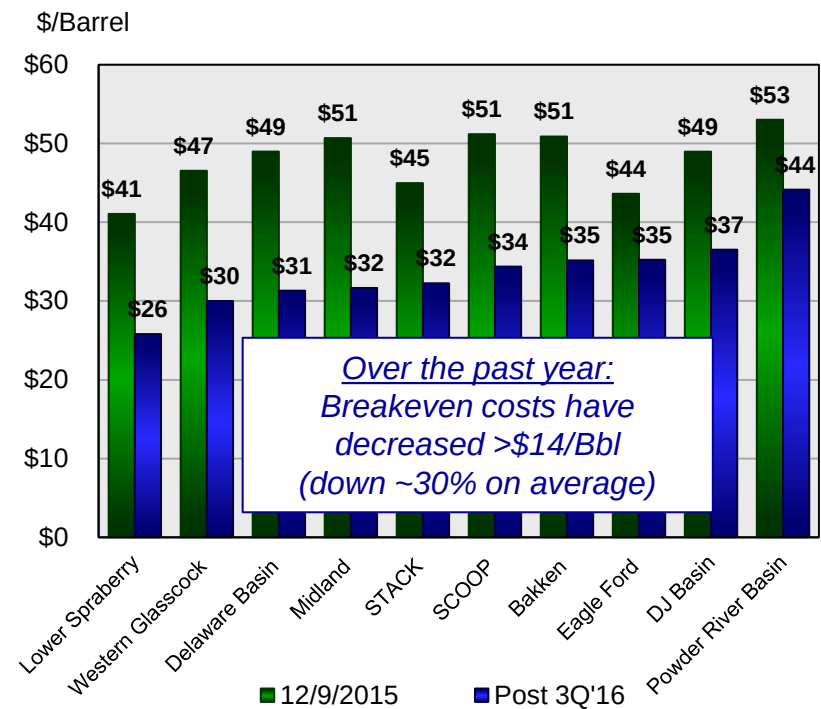
Becoming Cheaper and More Abundant

Technology has Reduced Costs and Increased Effectiveness

U.S. Oil and Gas Proved Reserves^(a)



U.S. Shale Breakeven Cost Curve^(b)



(a) EIA, 2015 U.S. Crude Oil and Natural Gas Proved Reserves, December 2016. Crude oil includes lease condensate proved reserves.

(b) Based on JPM research. Assumes 15% IRRs.

The Need for Fossil Fuel

- Fossil fuels are essential to our way of life
- They are affordable, dependable, plentiful and are becoming more affordable, plentiful and environmentally sustainable due to advancements in technology
- Fossil fuels are supported by enormous installed infrastructure that would take decades and substantial cost to replace
- Increased natural gas use has been and will continue to be critical to meeting climate goals
 - Replacing coal-fired power generation as plants are retired
 - Backstopping less reliable solar and wind generation
 - The International Energy Agency forecasts that even under the Paris Climate Accord, natural gas consumption will increase 50% through 2040^(a)
 - And the world will still be using ~103 MMBbl/d of crude oil – even while hundreds of millions will remain without basic energy services^(a)

Fossil Energy Demand is Strong

Natural Gas

- Multiple trends driving increased demand for U.S. natural gas

		2014	2015	2016E	2017E	2018E
Power Gen^(a)	Nat gas-share	28%	33%	34%	32%	33%
	Coal-share	39%	33%	30%	32%	32%
Exports to Mexico (Bcf/d)^(b,c)	KM Pipelines	1.9	2.3	2.8		
	Non-KM	0.1	0.5	0.8		
	Total	2.0	2.9	3.6	4.1	4.4
LNG Exports (Bcf/d)^(b)	Net LNG Exports from U.S.	0.0	-0.1	0.4	1.5	3.2

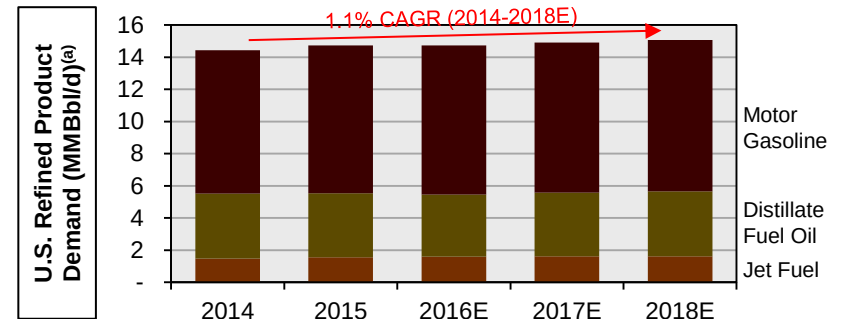
Natural Gas Liquids (NGL)

- Petchem NGL demand projected to increase 33% by 2018
- NGL exports projected to increase 32% by 2018

		2014	2015	2016E	2017E	2018E	Δ % '15-'18E
NGL Demand (MMBbl/d)^(d)	Petchem	1.5	1.6	1.6	1.8	2.1	33%
	Export	0.7	1.0	1.2	1.2	1.3	32%
	Other	1.4	1.4	1.4	1.4	1.4	0%
	Total	3.6	4.0	4.2	4.4	4.8	23%

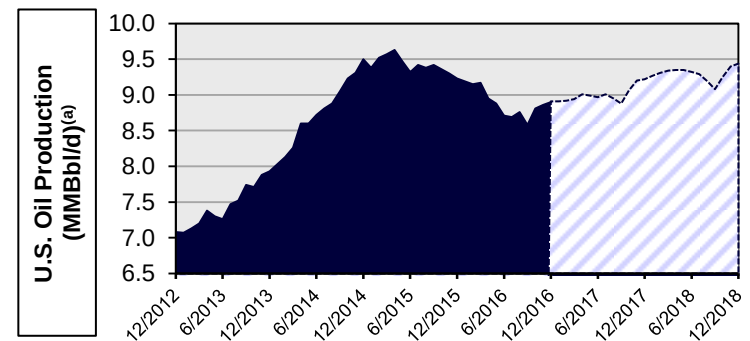
Refined Products

- Continued steady, modest volume growth
- Inflation-based tariff adjustment mechanism



Crude Oil

- Oil price decrease led to declines in U.S. production
- Market expected to balance in second half of 2017



(a) EIA, Short-term Energy Outlook, January 2017.

(b) Wood Mackenzie, Fall 2016 North America Gas Long-Term Outlook, December 2016.

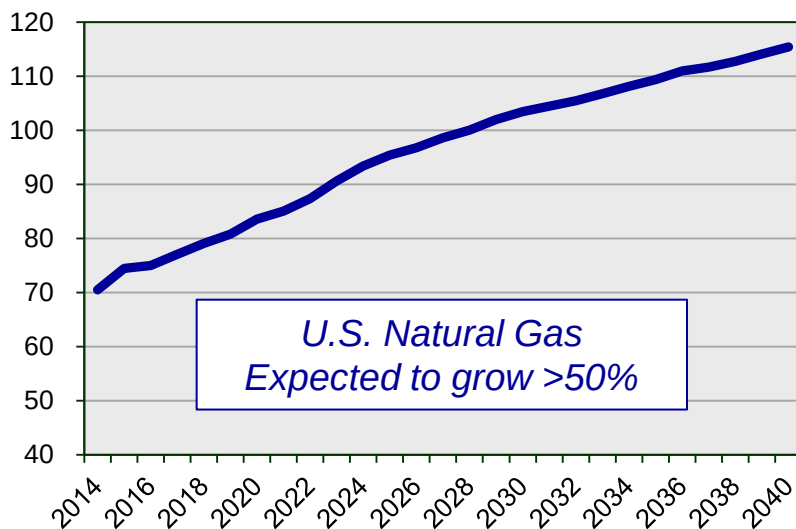
(c) KM Pipelines calculation of exports to Mexico includes its deliveries into the NET Mexico pipeline. Non-KM deliveries is adjusted by an offsetting amount.

(d) Wells Fargo, Quarterly NGL Supply/Demand Update, November 2016.

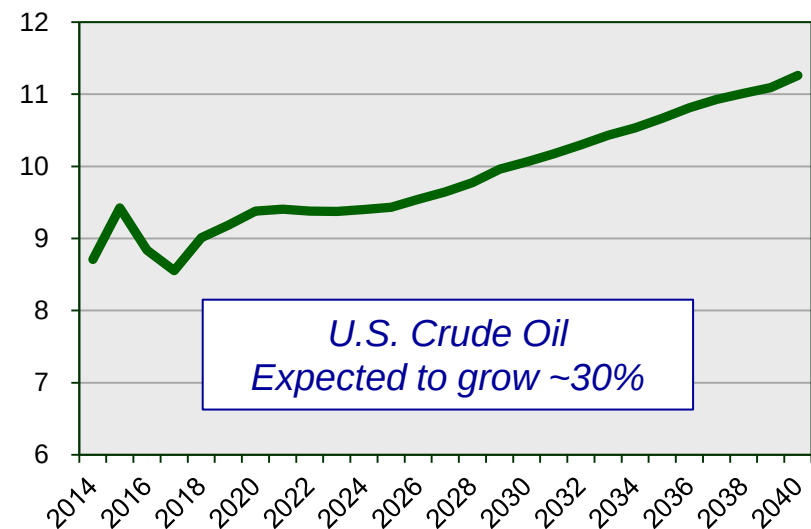
Long Term Demand is Strong

- Substantial natural gas and oil growth expected for the foreseeable future

U.S. Natural Gas Production (Bcf/d)^(a)



U.S. Crude Oil Production (MMBbl/d)^(a)



Kinder Morgan's Role

Well-Positioned to Support Future of Fossil Fuels

- The nation needs fossil fuels and the infrastructure that delivers them
- Pipelines are the safest, most economic and environmentally friendly means of transporting U.S. fuels
 - Damage and injury rates per billion ton-miles: 0.9 for natural gas pipelines, 0.6 for liquids pipelines, 2.1 for rail and 20.0 for road transportation^(a)
- Kinder Morgan is well positioned to take advantage of this growth
 - Kinder Morgan moves ~40% of the natural gas consumed in the U.S.; expects to maintain or expand that share
 - Extensive network of ~84,000 miles of pipelines (~70,000 miles of natural gas pipelines) which leads to opportunities to invest and expand the network
- Increased volumes = increased value of our infrastructure

Operational Excellence

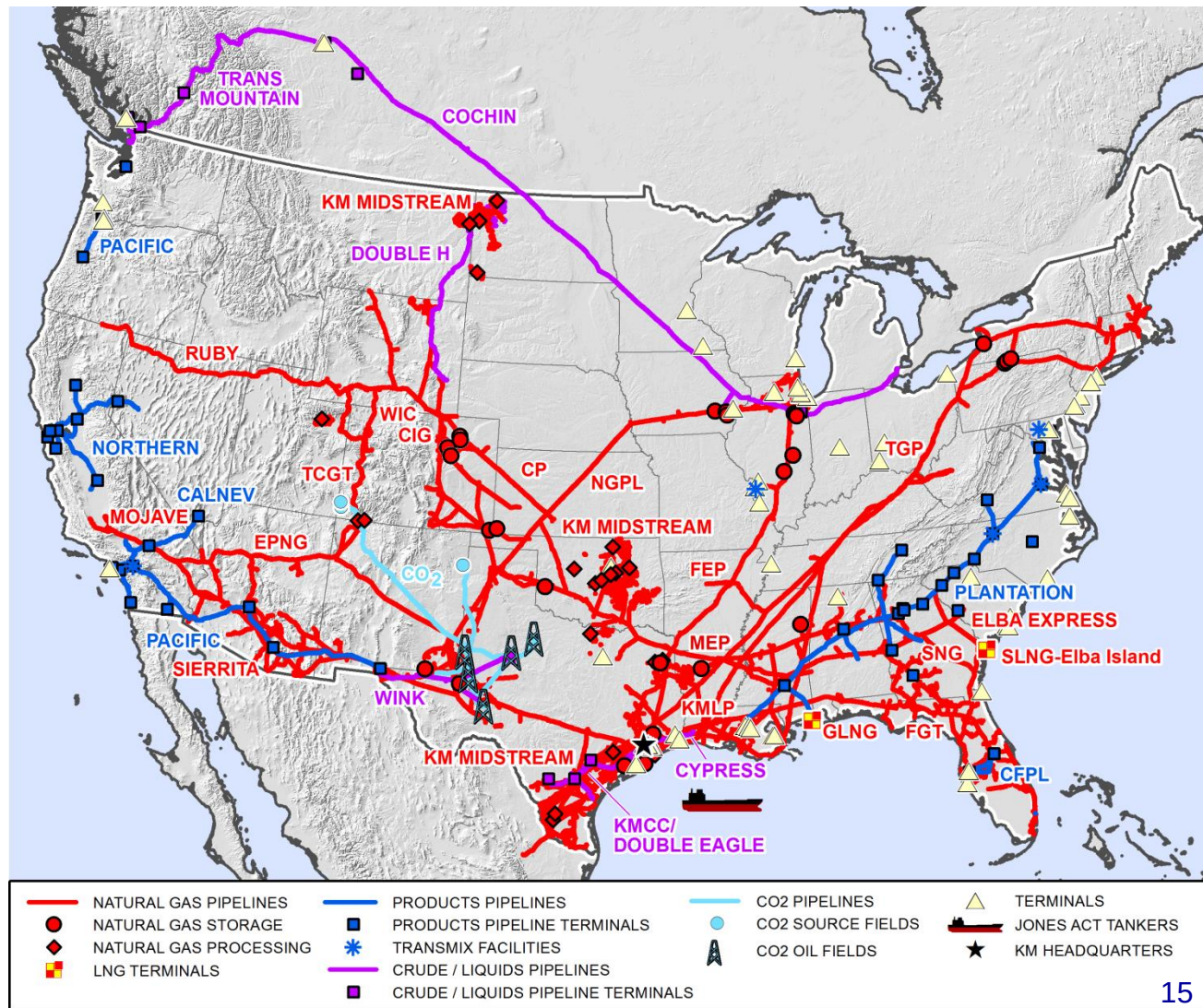
Steve Kean

President and Chief Executive Officer

Unparalleled Asset Footprint

Largest Energy Infrastructure Company in the U.S.

- **Largest natural gas network in North America**
 - Own or operate ~70,000 miles of natural gas pipeline
 - Connected to every important natural gas resource play in the U.S.
- **Largest independent transporter of petroleum products in North America**
 - Transport ~2.1 MMBbl/d^(a)
- **Largest transporter of CO₂ in North America**
 - Transport ~1.3 Bcf/d of CO₂^(a)
- **Largest independent terminal operator in North America**
 - Own or operate ~155 terminals^(b)
 - ~152 MMBbls liquids capacity
 - Handle ~53 MMtons of dry bulk products^(a)
 - Own 16 Jones Act vessels (including 4 under construction)
- **Only Oilsands pipeline serving the West Coast**
 - Transports ~300 MBbl/d to Vancouver/Washington State; planned expansion takes capacity to 890 MBbl/d



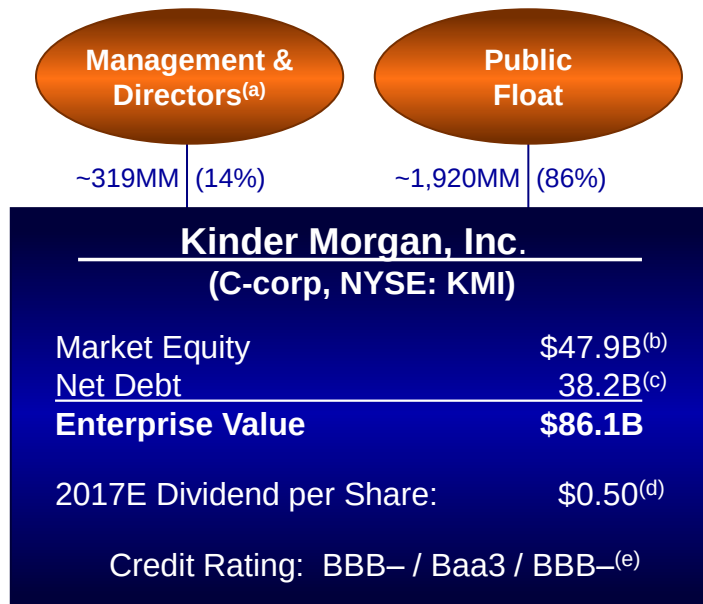
(a) 2017 budget.

(b) Excludes assets to be divested.

KMI Overview

Management Aligned with Investors; 14% Stake in KMI

Simple Public Structure



Simple Structure:

- One equity base and dividend
- One debt rating
- No structural subordination
- No incentive distribution rights

- Highly liquid: Nearly 15 million KMI shares traded daily on average during 4Q 2016

(a) Includes Form-4 filers and unvested restricted shares.

(b) Market prices as of 12/30/2016; KMI market equity based on ~2,239 million shares outstanding (including unvested restricted stock) at a price of \$20.71, ~293 million warrants at a price of \$0.01, and 32 million mandatorily convertible depositary shares at a price of \$48.65.

(c) Debt of KMI and its consolidated subsidiaries as of 12/31/2016, net of cash, and excluding fair value adjustments and Kinder Morgan G.P., Inc.'s \$100 million preferred stock due 2057.

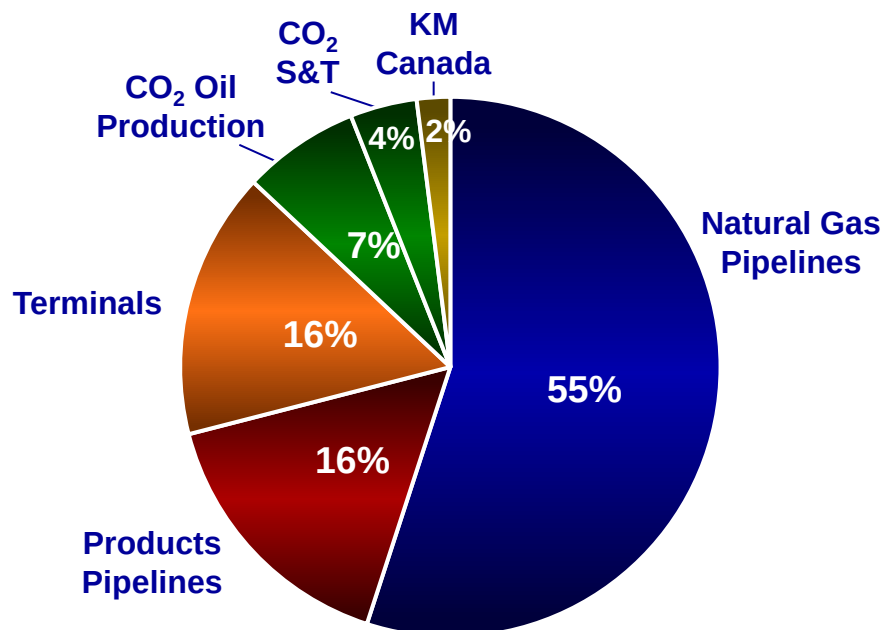
(d) Declared dividend per share per 2017 budget.

(e) KMI corporate credit ratings from S&P (Stable outlook), Moody's (Stable) and Fitch (Stable), respectively.

Segment Overview

93% Pipelines & Terminals

2017 Budgeted Segment
EBDA = \$7.7 billion^(a)



91% of cash flows fee-based for 2017;
97% fee-based or hedged

Natural Gas Pipelines

- 73% interstate pipelines
- 9% intrastate pipelines & storage
- 18% gathering, processing & treating
 - 88% fixed-fee (~27% of which is take-or-pay)

Products Pipelines

- 62% refined products
- 38% crude/liquids

Terminals

- 81% liquids
- 19% bulk

CO₂

- 34% CO₂ transport and sales
- 66% oil production-related
 - Production hedged (Bbl/d)^(b):

Year	Hedged Vol.	% Hedged	Avg. Px.
2017	35,109	75%	\$59
2018	15,029	53%	\$65
2019	8,100	33%	\$57
2020	4,200	20%	\$53
2021	0	0%	\$-

Kinder Morgan Canada

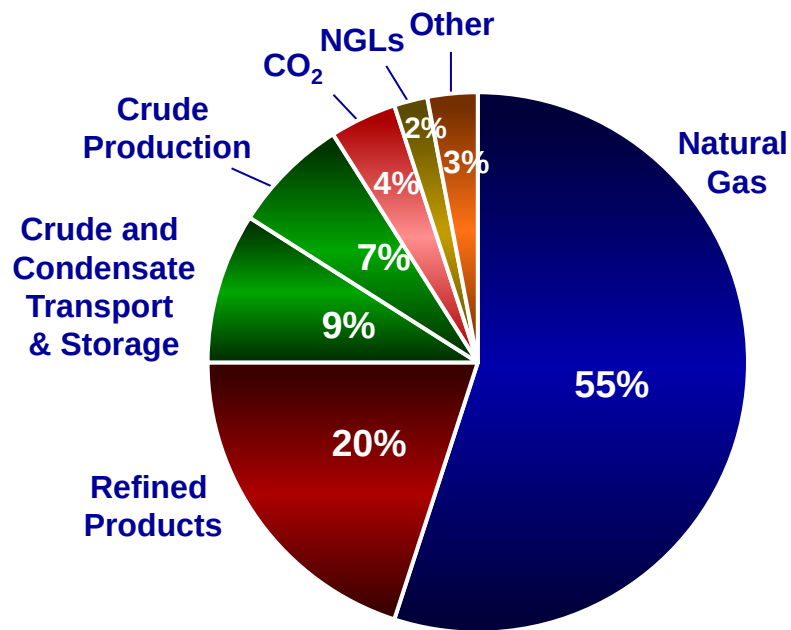
- 100% petroleum pipelines

(a) 2017 budgeted Segment EBDA before Certain Items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).

(b) Percentages based on currently hedged crude oil and propane volumes as of 12/31/2016 relative to crude oil, propane and heavy NGL (C4+) net equity production projected for 2017, and the Ryder Scott reserve report for 2018-2021.

KMI Overview by Product Served^(a)

Natural Gas is our Largest Market



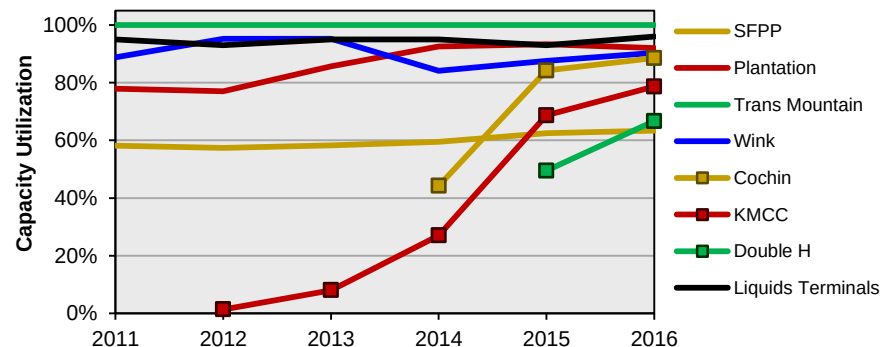
**91% of cash flows fee-based for 2017;
97% fee-based or hedged**

Stability of Cash Flows

- **Natural gas:** ~80% take-or-pay cash flow
- **Refined products:** competitively advantaged connection between refineries and end markets (includes ~61% of KMT liquids business)
 - Piped volumes within ~1.5% of budget over past 7 years
 - Terminals utilization ~96% since 2001
- **Crude and condensate:** >95% take-or-pay cash flow
 - KMCC, Splitter, Double H, Wink, Trans Mountain, and including ~24% of KMT liquids business
- **Carbon dioxide (CO₂):** >80% take-or-pay cash flow
- **NGLs:** >95% take-or-pay cash flow

Refined Product and Liquids Assets

Location matters, contracts matter

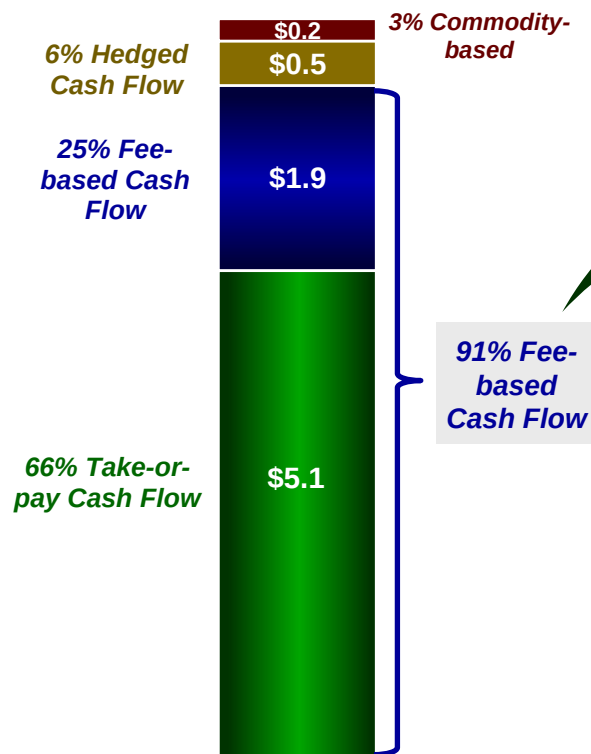


(a) All percentages based on 2017 budgeted Segment EBDA before Certain Items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).

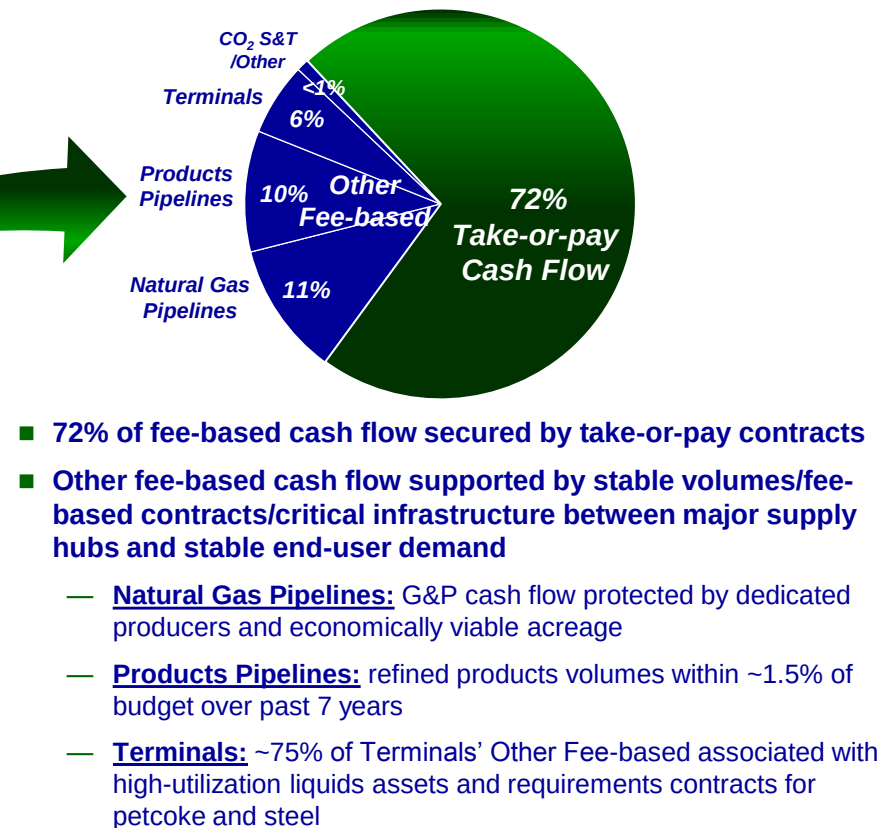
KMI's High Quality Cash Flow

Not all "fee-based" cash flow is created equal

**2017 Budgeted Segment
EBDA = \$7.7 billion^(a)**



**Composition of 91%
Fee-based Cash Flow**

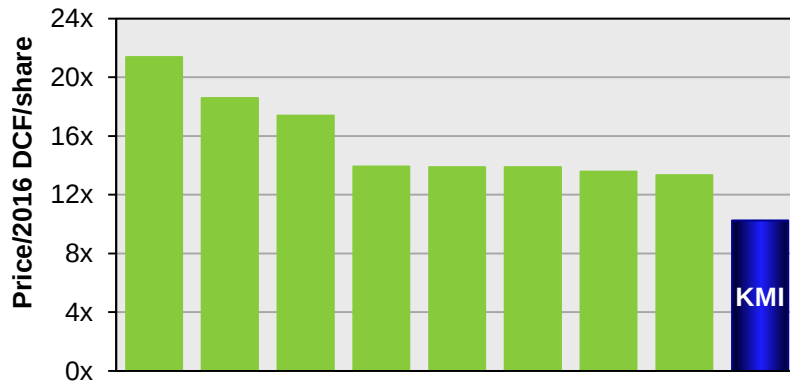


(a) Based on 2017 budgeted Segment EBDA before Certain Items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).

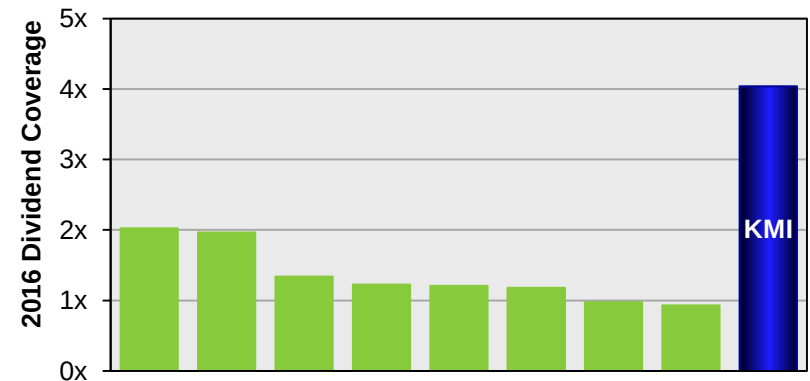
KMI: Compelling Investment Thesis

Attractive Relative Value, Best in Class Coverage

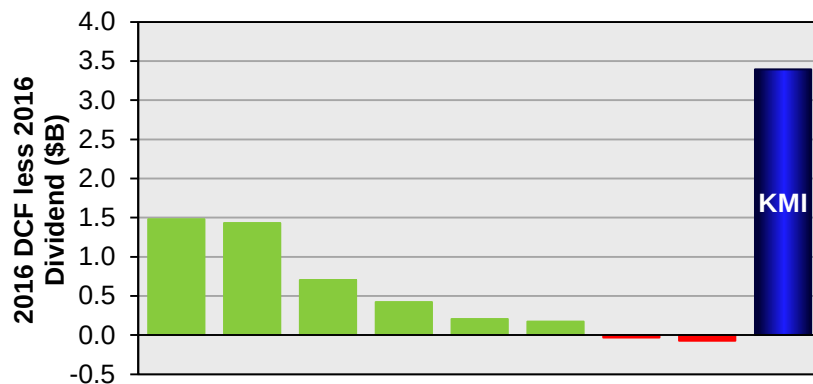
Attractive Relative Value^(a)



Best in Class Coverage^(b)



Insulated from Capital Market Risk^(c)



KMI Positioning

- Best in class dividend coverage
- No reliance on equity or debt markets in 2017 and beyond to fund growth projects
- Secure cash flow; 97% fee-based or hedged for 2017
- Significant growth opportunities

Notes: KMI financial measures before Certain Items. See Appendix for defined terms and reconciliations to GAAP measures.

Peer group: ENB, ETE, EPD, MMP, PAA, SE, WMB and TRP. Bloomberg consensus data as of 1/4/2017.

(a) 12/30/2016 share price divided by 2016 DCF per share. Peer estimates per Bloomberg consensus and actual for KMI.

(b) 2016 DCF per share divided by 2016 dividend per share. Peer estimates per Bloomberg consensus and actuals for KMI.

(c) DCF per share and dividend per share per Bloomberg consensus for peers and actual for KMI. Share count per Bloomberg for peers and actual for KMI.

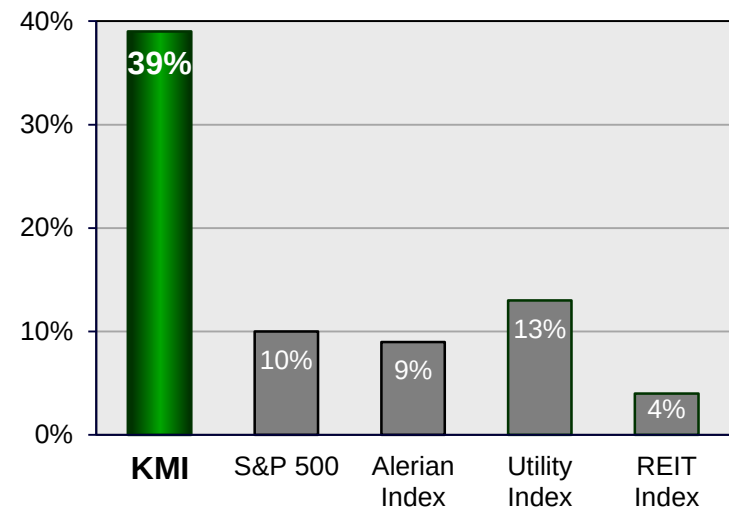
2016 Achievements

A Year of Progress

- ✓ **Improve balance sheet and liquidity**
 - Net debt/Adjusted EBITDA reduced from 5.6x at year-end 2015 to 5.3x at year-end 2016
 - \$2.8 billion of cash flow in excess of our dividend used to fund growth capital
 - Increased credit facility capacity by \$1.0 billion and raised a \$1.0 billion term loan at the beginning of the year; current liquidity is >\$5.0 billion
- ✓ **Secure strategic partners and divest non-core assets**
 - Strategic 50/50 joint venture with Southern Company on SNG pipeline
 - Secured 50% partner for Utopia pipeline project
 - Non-core asset divestitures: Parkway, bulk terminals, and a transmix facility
- ✓ **High-grade backlog**
 - Reduced overall backlog: placed ~\$1.8 billion in service, eliminated lower return projects and reduced project costs
 - Capex/EBITDA multiple improved from 7.5x at beginning of 2016 to 6.7x at beginning of 2017

Resulting in Strong Stock Performance

The market appreciated KMI's achievements in 2016...



... and we believe the best is yet to come

2017 Goals

- **Budgeted DCF/share of \$1.99**
- **Year-end 2017 budgeted net debt/Adjusted EBITDA of 5.4x**
 - Continue to find ways to accelerate the strengthening of our balance sheet
- **Meet or exceed our environmental and safety targets**
 - Perform better than industry average
 - Improve operational performance relative to our own past performance
- **Execute on our project backlog, place projects in-service on time and on budget**
- **JV or IPO of Trans Mountain**
- **Expect to communicate updated dividend guidance in latter part of 2017, with a view toward delivering additional value to shareholders in 2018**

Our Strategy

- **Focus on stable fee-based assets that are core to North American energy infrastructure**
 - Market leader in each of our business segments
 - Fees largely independent of underlying commodity prices and substantially secured by take-or-pay contracts
- **Maintain a strong balance sheet**
 - Our primary investing entity has been investment grade since inception
 - Reduced dividend demonstrates our commitment to investment grade and our ability to fund growth projects without need to access capital markets
- **Operate safely and efficiently**
 - Control costs: It's investors' money, not management's – treat it that way
 - Performing better than industry averages; target zero incidents
- **Leverage asset footprint to seek attractive capital investment opportunities, both expansion and acquisition**
 - Since 1997, Kinder Morgan has completed approximately \$31.4 billion in acquisitions and invested approximately \$27.3 billion in greenfield/expansion projects^(a)
- **Transparency to investors**
- **Keep it simple**

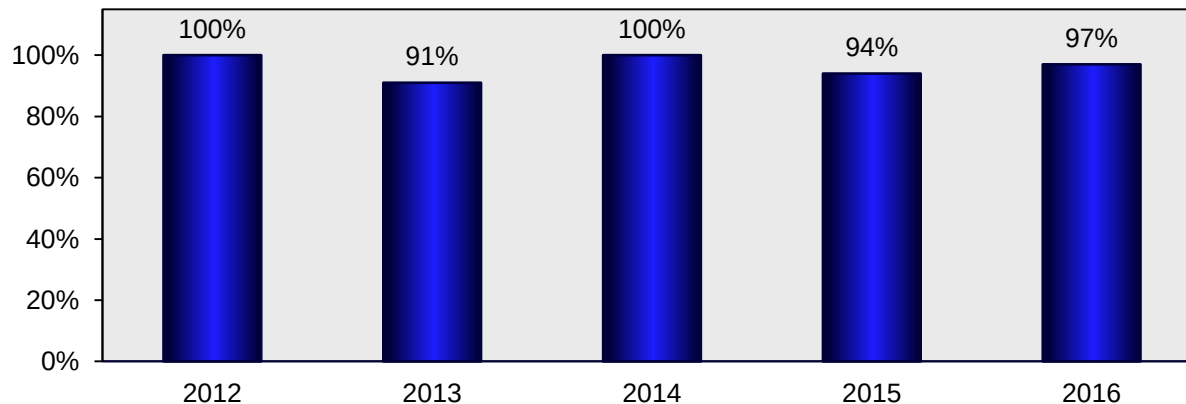
(a) From 1997 inception through 2016; represents combined investment of KMP (1997-2014), EPB (2013-2014), and KMI (2015-2016).

Asset Integrity and Safety are Top Priorities

Consistent, Better-than-industry Performance Across our Businesses

- Safe operation of our assets is mission critical to our long-term success
- Continuous reduction in risk to the public, employees, contractors, assets and the environment
- We strive for continual improvement in safety and efficiency of existing operations
- Well-executed expansions and effective integration of acquired operations
- Consistently perform better than industry average
 - Track over 36 safety metrics and post monthly updates to our public website
 - Currently better than industry in 35 of 36 metrics

% of Safety Metrics KM Performed Better than or Equal to Industry^(a)



(a) Based on year-end Kinder Morgan metrics versus most applicable industry performance.

Business Risks

- **Regulatory**
 - FERC rate cases (Products pipelines and Natural Gas pipelines)
 - Legislative and regulatory changes
- **CO₂ crude oil production volumes**
- **Throughput on our volume-based assets**
- **Commodity prices**
 - 2017 budget price assumptions: \$53/Bbl average strip price for crude, and \$3.00/MMBtu average strip price for natural gas
 - Price sensitivities (full-year):
 - \$1/Bbl change in oil price = ~\$6 million DCF impact
 - 10¢/MMBtu change in natural gas price = ~\$1 million DCF impact^(a)
 - 1% change in NGL/crude ratio = ~\$3 million DCF impact
- **Project cost overruns/in-service delays**
- **Economically sensitive businesses (e.g. steel and coal terminals)**
- **Foreign exchange rates**
 - 2017 budget rate assumption of 0.77 CAD/USD
 - Price sensitivity (full-year): 0.01 ratio change = ~\$2.3 million DCF impact
- **Environmental (e.g. pipeline/asset failures)**
- **Terrorism**
- **Interest rates**
 - Full-year impact of 100-bp increase in floating rates equates to a ~\$110 million increase in interest expense^(b)

(a) Natural Gas Midstream sensitivity incorporates current hedges, and assumes ethane recovery for majority of year, constant ethane frac spread, and assumes other NGL prices maintain same relationship with oil prices.

(b) As of 12/31/2016 approximately \$11.0 billion of KMI's net debt was floating rate (~28% floating).

The Best is Yet to Come

Positioned to Succeed for the Long-Term

- World class set of midstream assets
- Secure and growing fee-based cash flows
- Disciplined allocator of capital; high bar for new investment opportunities
- Investment grade balance sheet and substantial liquidity
- As future cash flow exceeds investment needs, we have value-enhancing options:
 - Invest in high-return acquisitions and/or expansions
 - Further de-lever balance sheet
 - Return cash to shareholders via increased dividends and/or share buybacks
 - Expect to communicate updated dividend guidance in latter part of 2017, with a view toward delivering additional value to shareholders in 2018
- Experienced management team aligned with investors
- Transparency to investors

Overview of Business Segments

Natural Gas Pipelines

Segment Outlook

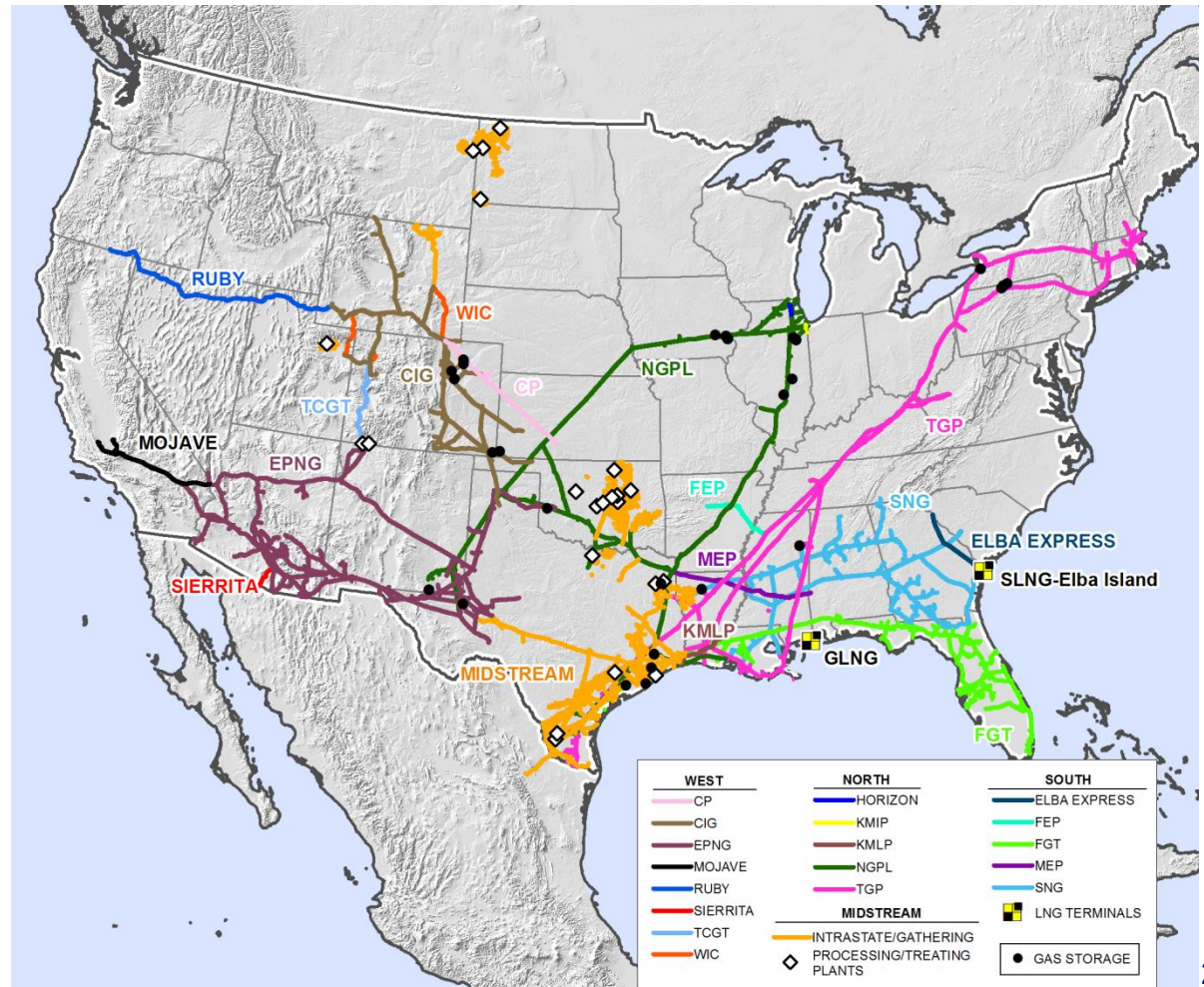
Well-positioned connecting key natural gas resources with major demand centers

Long-term Growth Drivers:

- LNG exports
 - Liquefaction facilities
 - Pipeline infrastructure
- Exports to Mexico
- Gas demand for power generation
 - Coal plant retirements
 - Regional gas-fired power demand growth
 - Backstop for wind and solar
- Industrial demand growth
- Shale-driven expansions / extensions
- Acquisitions

Project Backlog:

- \$3.5 billion of identified growth projects over next four years (2017-2020)^(a), including:
 - LNG liquefaction (Elba Island)
 - Transport projects supporting LNG liquefaction, including Elba Express
 - Expansions to Mexico border
 - TGP North-South projects



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

Natural Gas Transportation & Storage

55% of 2017 Budgeted Segment EBDA before Certain Items^(a)

Natural gas transport & storage is KMI's largest business

- **U.S. natural gas demand^(b) expected to rise by 35% through 2026^(c)**
 - KM moves about 40% of natural gas consumed in the U.S.
- **Transportation demand drivers:**
 - Power demand, exports (Mexico and LNG) and industrial market
- **Storage demand drivers:**
 - Power and LNG exports have variable-load characteristics which require storage support
 - KM well-positioned to meet demand as the largest storage operator in the U.S. with 689 Bcf out of 4.3 Tcf market (~16%)
 - Increased contracting activity at improved rates in the Interstate and Intrastate markets
- **Gathering & processing trends:**
 - Gathering supported by overall volume trends
 - Processing supported by new LPG export capacity (docks and fleet) and Gulf Coast petrochemical demand

U.S. Natural Gas Supply/Demand Outlook ^(c) (Bcf/d)				
Demand	2016	2021	2026	
LNG net exports	0.4	7.4	12.8	
Mexican net exports	3.6	5.6	5.8	
Power	27.6	28.4	30.0	
Industrial	21.2	23.9	24.8	
Other	26.2	31.0	33.5	
Total U.S. demand	79.0	96.3	106.9	
Increase from 2016		22%	35%	
Supply	2016	2021	2026	
Marcellus/Utica	22.6	37.5	44.3	
Haynesville	5.0	6.2	8.4	
Eagle Ford	4.5	7.7	9.5	
All other	46.9	44.9	44.7	
Total U.S. supply	79.0	96.3	106.9	

**Greater U.S. volumes =
increased value of KMI assets**

(a) Based on KMI 2017 budgeted Segment EBDA before Certain Items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).

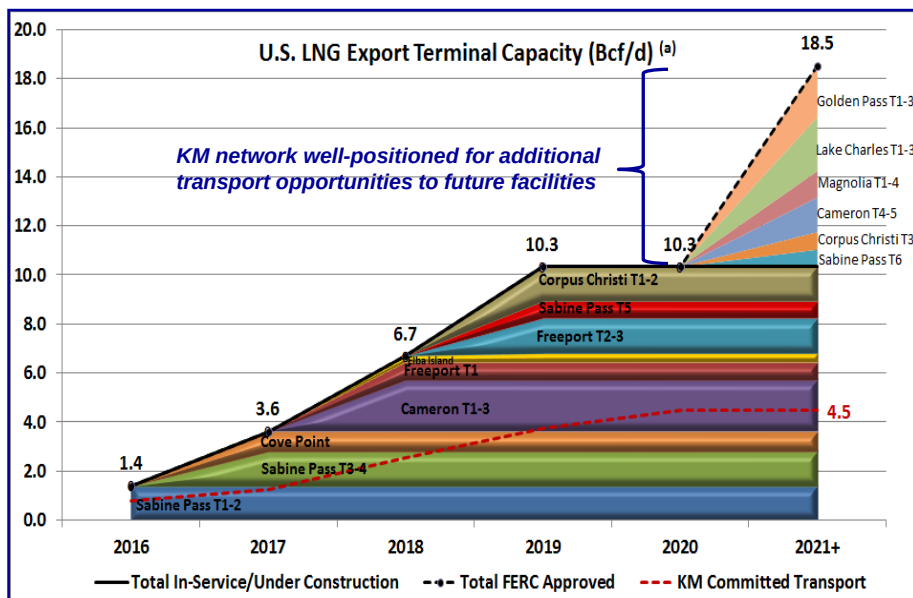
(b) Including net exports of liquefied natural gas (LNG) and net exports to Mexico.

(c) Wood Mackenzie, Fall 2016 North America Natural Gas Long-Term Outlook, December 2016.

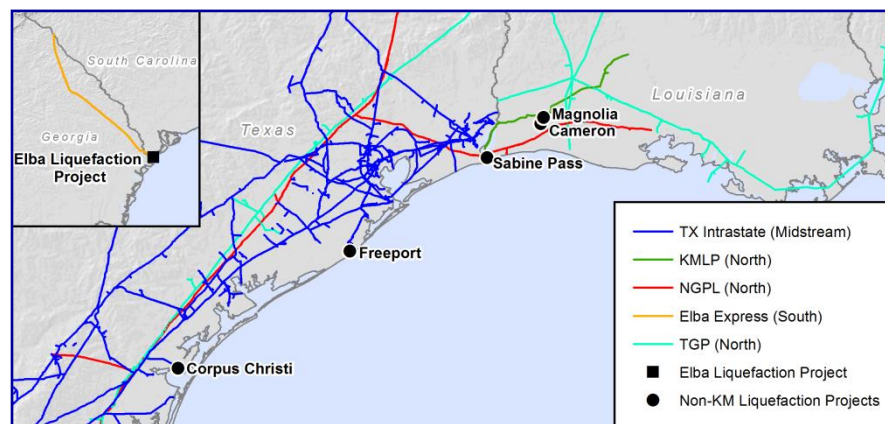
Drivers of Future Growth

LNG Exports

- **LNG Export Opportunity^(a)**
 - 18.5 Bcf/d of FERC approved projects
 - 10.3 Bcf/d of projects under construction
 - 9.8 Bcf/d of additional projects pending approval
- **Elba Liquefaction – KM facility at Elba Island, GA**
- **LNG Transport**
 - 4.5 MMDth/d of contracted transport capacity
 - Total capital of \$981 MM
 - Avg. contract term: 19 years
 - Seven active projects on five KM pipelines



KM Asset	KM Project/Transportation (Terminal)	Contracted Capacity (MDth/d)	In-Service Date	KM Capital (\$MM)
NGPL	Firm Transport (Sabine Pass)	550	In-Service	N/A
EEC	EEC for Shell (Elba Island)	436	2/2017-11/2018	\$102.2
TGP	SW Louisiana Supply (Cameron)	900	2/2018	\$178.5
NGPL	Gulf Coast Southbound (Corpus Christi)	385	4Q/2018	\$106.1
Intrastate	TX Intrastate Crossover (Corpus Christi/Freeport)	590	1Q-3Q 2019	\$182.1
TGP	Lone Star (Corpus Christi)	300	7/2019	\$133.8
KMLP	Sabine Pass Expansion	600	4Q/2019	\$151.3
KMLP	Magnolia LNG Expansion	700	4Q/2020	\$127.0



(a) FERC as of 1/5/17, industry and KM analysis.

Liquefaction at Elba Island

Elba Liquefaction Company (ELC) / SLNG



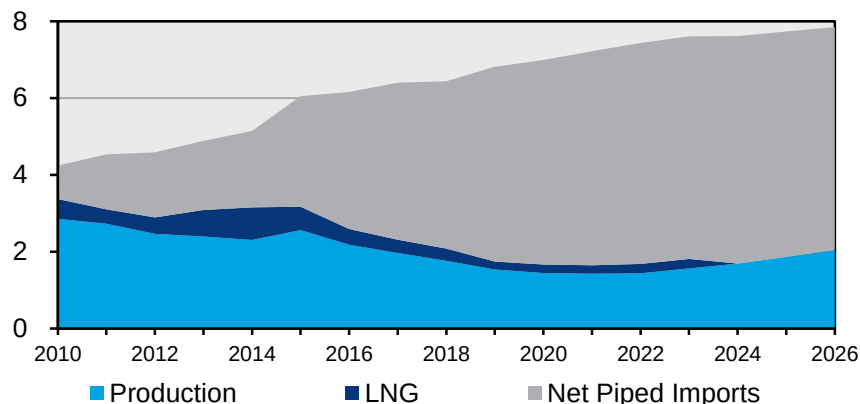
- **Capacity:**
 - LNG output capacity equivalent to 350 MMcf/d
- **Capital (100%):**
 - ELC: \$1,436.4 MM
 - SLNG: \$ 433.8 MM
- **Phased In-service: Mid 2018 through early 2019**
- **Project Scope:**
 - Facilities for liquefaction (10 modular units)
 - Ship loading facilities; boil-off gas compression
- **Avg. Contract Term: 20 years**
- **Current Status:**
 - FERC certificate issued June 2016
 - FERC denied requests for rehearing Dec 2016
 - Shell has committed to entire capacity of facility, as well as Elba Express expansion
 - DOE FTA and non-FTA authorizations received
 - Construction underway
- **Major Milestones:**
 - JV negotiations for ELC are ongoing

Drivers of Future Growth

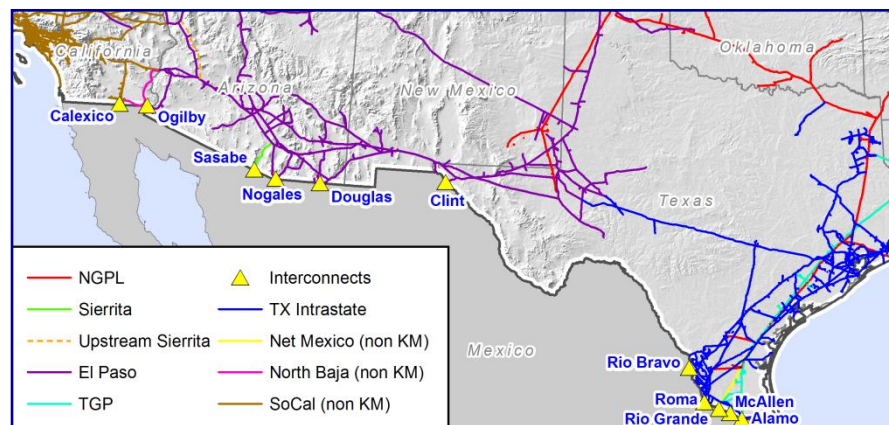
Kinder Morgan Delivers ~76% of U.S. Exports to Mexico

- Exports to Mexico are forecasted to increase by 2.0 Bcf/d to 5.6 Bcf/d by 2021^(a)
- KM deliveries to Mexico ~2.8 MMDth/d^(b) through 17 interconnects (12 direct & 5 indirect)
 - KM up 20% from 2015; 76% of 2016 U.S. total
 - Well positioned to serve incremental demand through extensive network connected to multiple prolific supply basins
- KM projects and new long term commitments for export to Mexico entered into since 2013:
 - Capacity: ~2.4 MMDth/d
 - Capital: ~\$667 MM

Mexico Gas Supply (Bcf/d)^(a)



KM Asset	KM Project / Transportation (Shipper)	Contracted Capacity (MDth/d)	In-Service Date	KM Capital (\$MM)
Sierrita	Sierrita Gas PL (CFE)	200	10/2014	\$64.1
EPNG	S. Mainline Exp. (CFE)	471	10/2014 - 7/2020	\$134.8
TX Intra	Mier Monterrey (MexGas/Others)	225	12/2014	\$94.0
EPNG	Transport (CFE)	85	2014 / 2017	NA
TGP	S. System Flex (MexGas)	500	1/2015 - 12/2015 - 10/2016	\$229.6
TGP	Transport (MexGas)	100	1Q 2016	NA
TX Intra	Crossover Project ^(c)	527	9/2016	\$125.0
EPNG	Transport (GIGO)	20	4Q 2016	NA
EPNG	Trans. (Mexicana de Cobre)	9	4Q 2016	NA
Sierrita	Sierrita Gas PL Expansion (CFE)	230	4/2020	\$19.8



(a) Wood Mackenzie, Fall 2016 North America Natural Gas Long-Term Outlook, December 2016.

(b) 2016 calendar year average.

(c) Commitment to part of larger Crossover project designed to support LNG Exports, Gulf Coast Industrial demand and Exports to Mexico.

Drivers of Future Growth

Other

■ Power generation

- Continued trend of generators procuring firm transportation and storage services to ensure their performance in ISO capacity reliability programs
- Increasing need for transportation, storage and ancillary services to backstop variable renewable generation

■ New opportunities in growing export markets

- Storage and ancillary services in support of LNG liquefaction and exports to Mexico

■ Industrial growth markets

- Well positioned to serve >\$170 billion announced U.S. natural-gas related petrochemical expansion projects (\$76 billion completed or under construction)^(a)

■ Residential and commercial markets

- Small to moderate expansions and extensions off our existing footprint to support LDC growth around the country, especially New England

■ Supply-based expansions/extensions

- Expansions and extensions off existing network to support growth as demand balances with existing supply

(a) American Chemistry Council, *Trade: A Pro-Growth, Pro-Competitiveness Agenda for Chemical Manufacturing factsheet*, December 21, 2016.

Products Pipelines

Segment Outlook

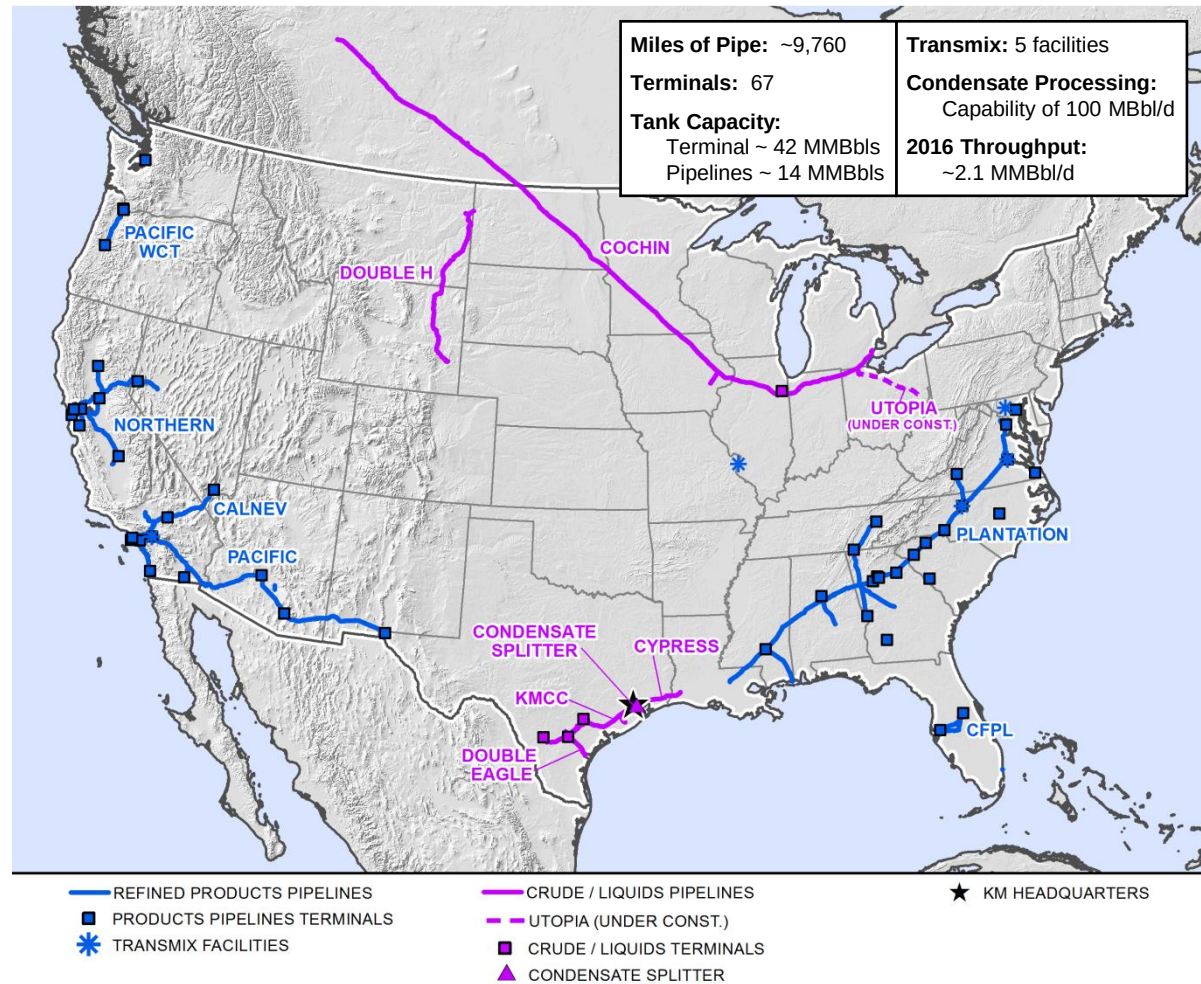
Stable, Strategic Assets

Long-term Growth Drivers:

- Increased demand for refined products volumes
- Development of shale play liquids transportation and processing (e.g. Utopia and KMCC / splitter)
- Tuck-in acquisitions (e.g. KM Phoenix Terminals)
- Expansion of refined products pipeline systems and Terminal Networks
- Repurposing portions of existing footprint in different product uses

Project Backlog:

- \$318 million of identified growth projects over next two years^(a) (first year total Adjusted EBITDA \$22.8 million^(b)), including:
 - Utopia
 - Multiple refined products Terminating and Bio Fuels projects



Stability and Growth^(a)

Refined Products^(b):

- **2016:**
 - Refined products volumes 1,651 MBbl/d, up 0.3% vs. 2015
 - Gasoline up 1.2%, diesel down 3.5%, jet fuel up 1.7%
- **2017:**
 - 1,676 MBbl/d budgeted, 1.5% up vs. 2016
 - Budget volume sensitivity: 1% change = \$7.5M

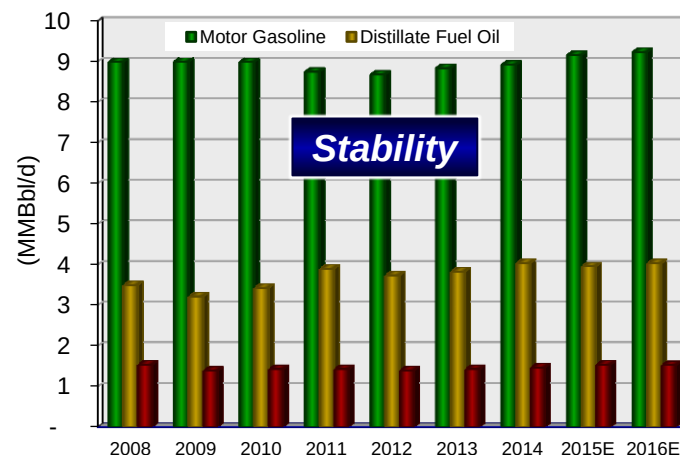
NGLs:

- **2016:**
 - NGL volumes 108 MBbl/d, up 2.7% vs. 2015
 - Drivers: higher volumes on Cochin Pipeline
- **2017:**
 - Budgeted volume up 5.6% vs. 2016
 - Drivers: Increased demand on Cochin; no forecasted turnaround in 2017 at Cypress Pipeline terminus

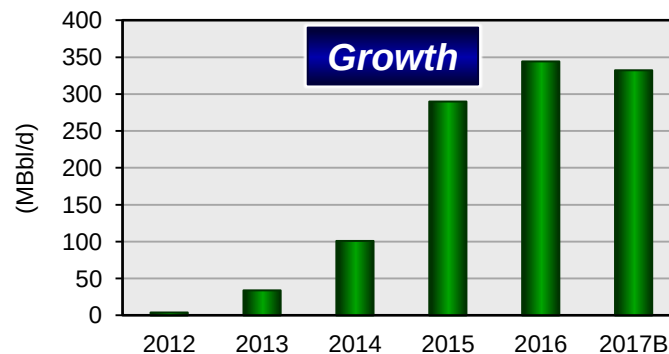
Crude/ Condensate:

- **2016:**
 - Crude/ condensate volumes 323 MBbl/d, up 18.3% vs. 2015
 - Drivers: expansion projects on KMCC/ Double Eagle and acquisition of Double H pipeline
- **2017:**
 - 312 MBbl/d budgeted, down 3.3% vs. 2016
 - Drivers: Decreased production from the Eagle Ford

U.S. Refined Product Consumption^(c)



KM Crude and Condensate Volume Ramp^(d)



(a) All volumes reflect KM-share for joint ventures.

(b) Parkway divested July 2016. Parkway volumes and revenue not included.

(c) EIA, Short-term Energy Outlook, January 2017.

(d) Combined throughput of KM crude / condensate pipelines: KMCC, Double Eagle and Double H.

KMCC / Double Eagle

Location, Contracts, Connectivity

Kinder Morgan Crude & Condensate (KMCC)

- Capacity = 300 MBbl/d, expandable to 360 MBbl/d; Approximately 90% of current capacity committed
- Provides Eagle Ford producers access to Houston Ship Channel (Refineries, Export Opportunities), KM Splitter, Phillips 66 Sweeny Refinery

Double Eagle Pipeline

- Capacity 100 MBbl/d; 75% of capacity committed; 50/50 JV w/ Magellan
- Provides Eagle Ford producers access to Magellan Corpus Christi Terminal and KMCC

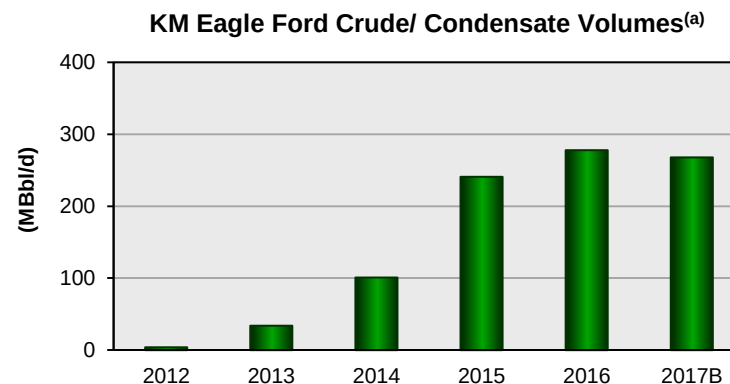


2016 Milestones

- KMCC / Double Eagle volumes grew 15.3% year over year as the full year impact of expansion projects and new customer commitments were realized
- KMCC volumes grew from 2015 to 2016, despite a 22% decline across the Eagle Ford^(b)

2017 Plans

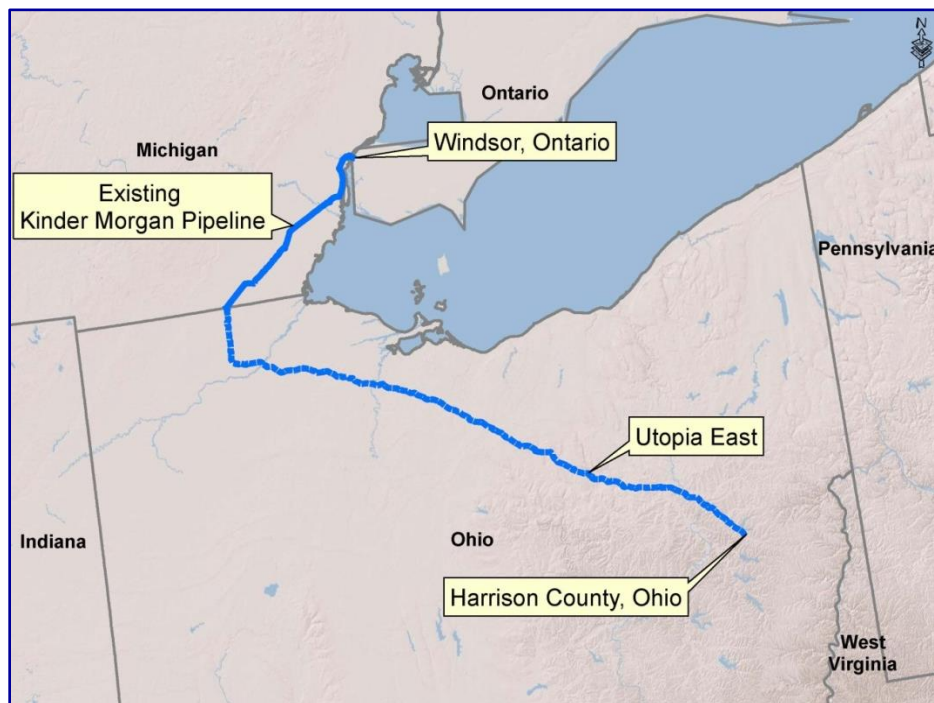
- Maintain volumes
- Focus on superior location, customer base, and connectivity



(a) Combined throughput of KMCC and Double Eagle.

(b) EIA, Drilling Report, January 2017.

Utopia Pipeline Project



■ Project Scope

- 50/50 JV with Riverstone Holdings closed on June 28, 2016
- 215 mile new build and existing 67 mile 12" pipeline
- Will transport ethane and ethane-propane mix from points in Harrison County, Ohio to Windsor, Ontario, Canada
- Supported by long-term, fee-based transportation agreement
- Initial pipeline capacity of 50 MBbl/d; expandable to 75 MBbl/d
- Approximate \$540 million^(a) investment

■ Market Drivers

- Utopia will provide a new feedstock source for petrochemical companies in Ontario, and a new market outlet for Utica NGL producers
- Common carrier pipeline system is supported by a long-term (>20 years), fee-based transportation services agreement

■ Project Status and Timeline

- ROW acquisition ongoing
- Commencement of construction 1Q 2017
- Planned in-service date of January 2018

(a) 100% project cost, excluding AFUDC.

Terminals

Segment Outlook

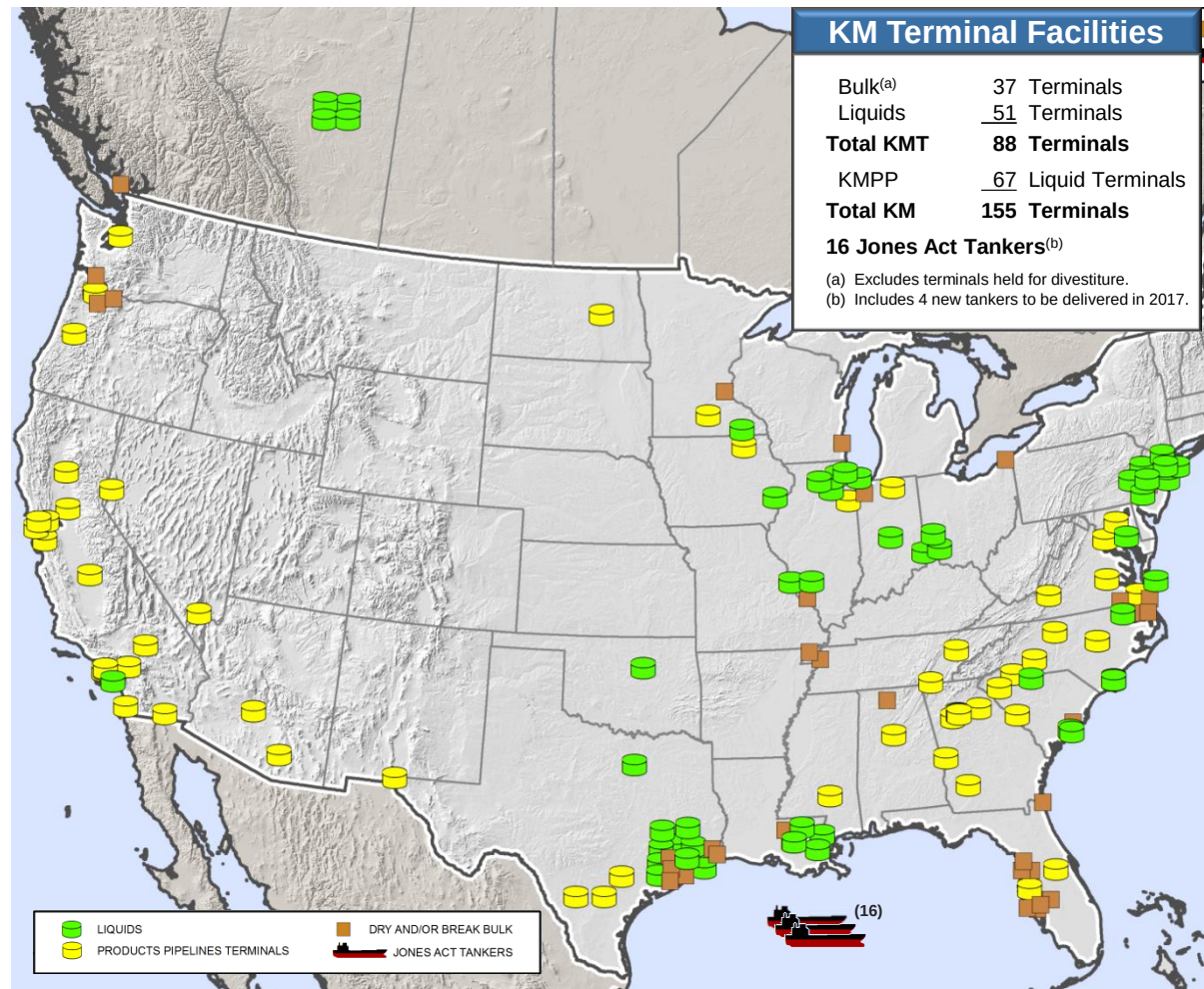
Diversified terminaling system in key refinery / market hubs

Long-term Growth Drivers

- Refined product supply and demand growth
- Gulf Coast liquids exports
- Chemical infrastructure and base business growth built on production increases
- Tuck-in acquisitions

Project Backlog

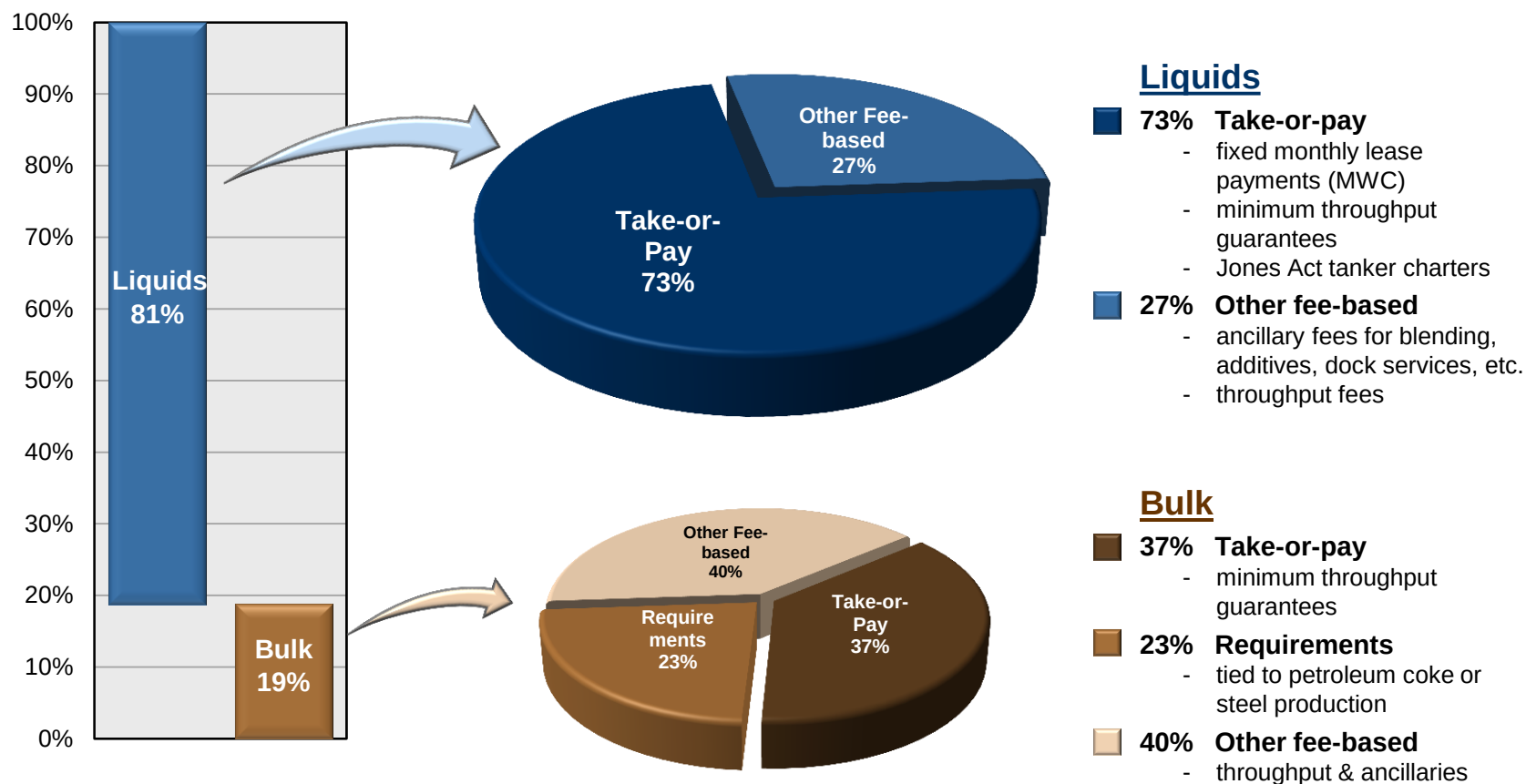
- \$1.4 billion of identified growth projects over the next two years^(a), including:
 - Houston Ship Channel network expansion
 - Edmonton merchant crude terminal
 - Jones Act tanker builds



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

Stable Fee-Based Business

- ~2/3 of KMT's 2017 budgeted EBDA is supported by take-or-pay contracts



**KMT 2017 Budgeted
EBDA = \$1,178 million**

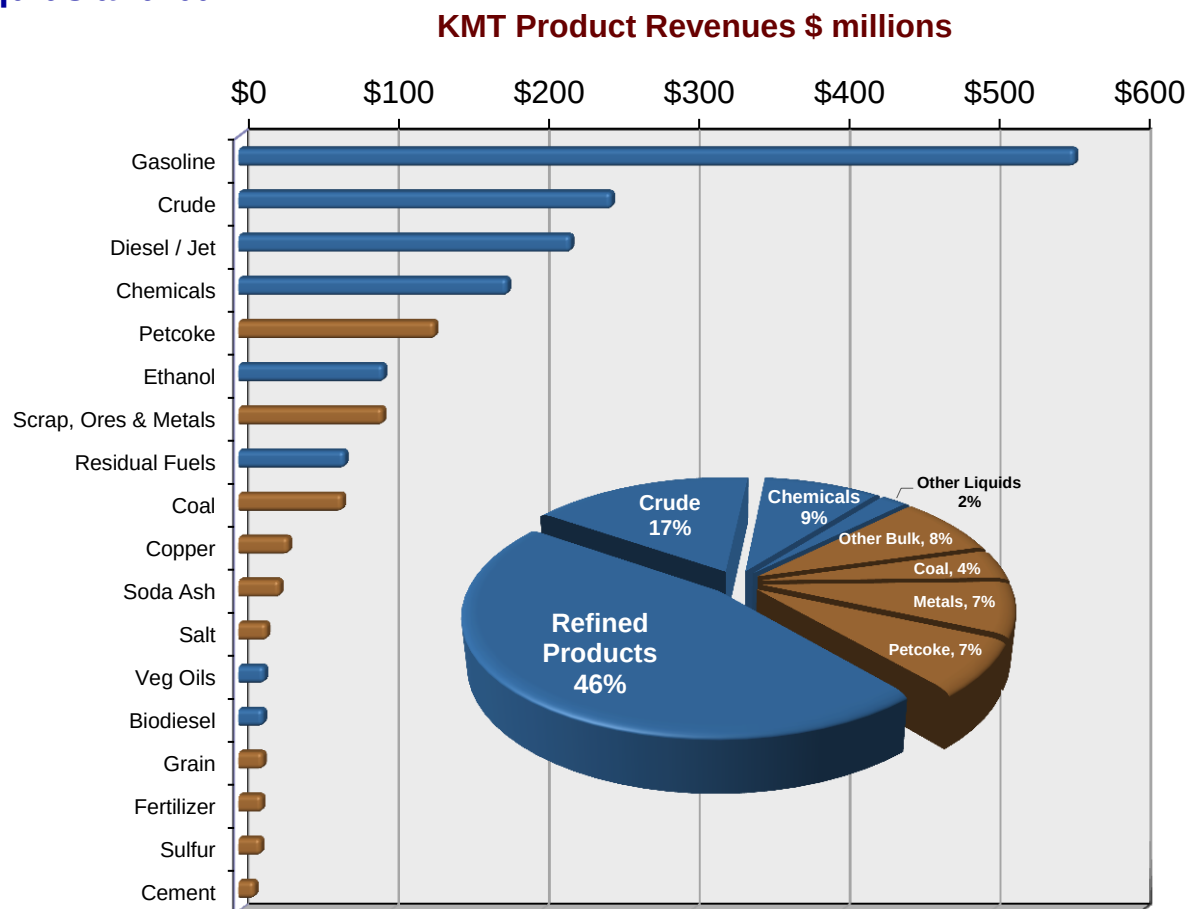
Diversified Revenues

■ Diversified revenues across liquids and bulk

	2017 Budget ^(a) (\$ millions)	(percent)
Liquids	\$1,426	74%
Bulk	\$500	26%
Total Revenue	\$1,926	100%

Top-10 Customers^(b)	\$911	47%
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	Average remaining contract term ^(c) (years)
Liquids	3.7
Bulk	4.9

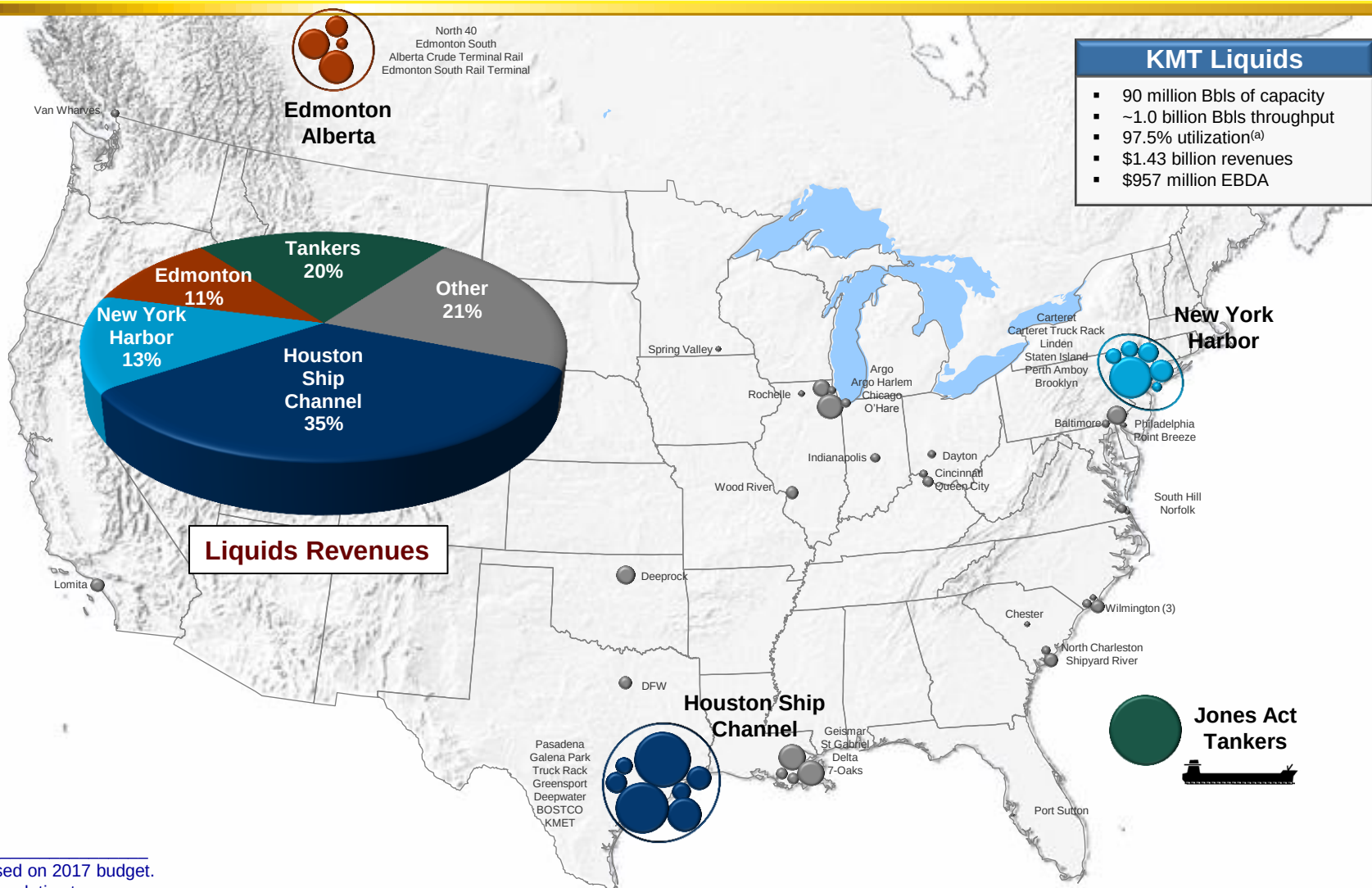


(a) 2017 budget includes non-controlling interests in certain terminals.

(b) No single customer is greater than 9.5% of revenues.

(c) Budget weighted average as of Jan 1, 2017.

KMT Presence in Liquids Hubs



All data is based on 2017 budget.

(a) Size is relative to revenues.

(b) Terminal utilizations reflect tankage unavailable for lease due to API inspections and routine maintenance.

Houston – Physical Connectivity

KMT's Houston Ship Channel terminal network is the largest integrated refined product terminalling system in the world: ~43 million barrels of capacity

■ Fee-Based Business

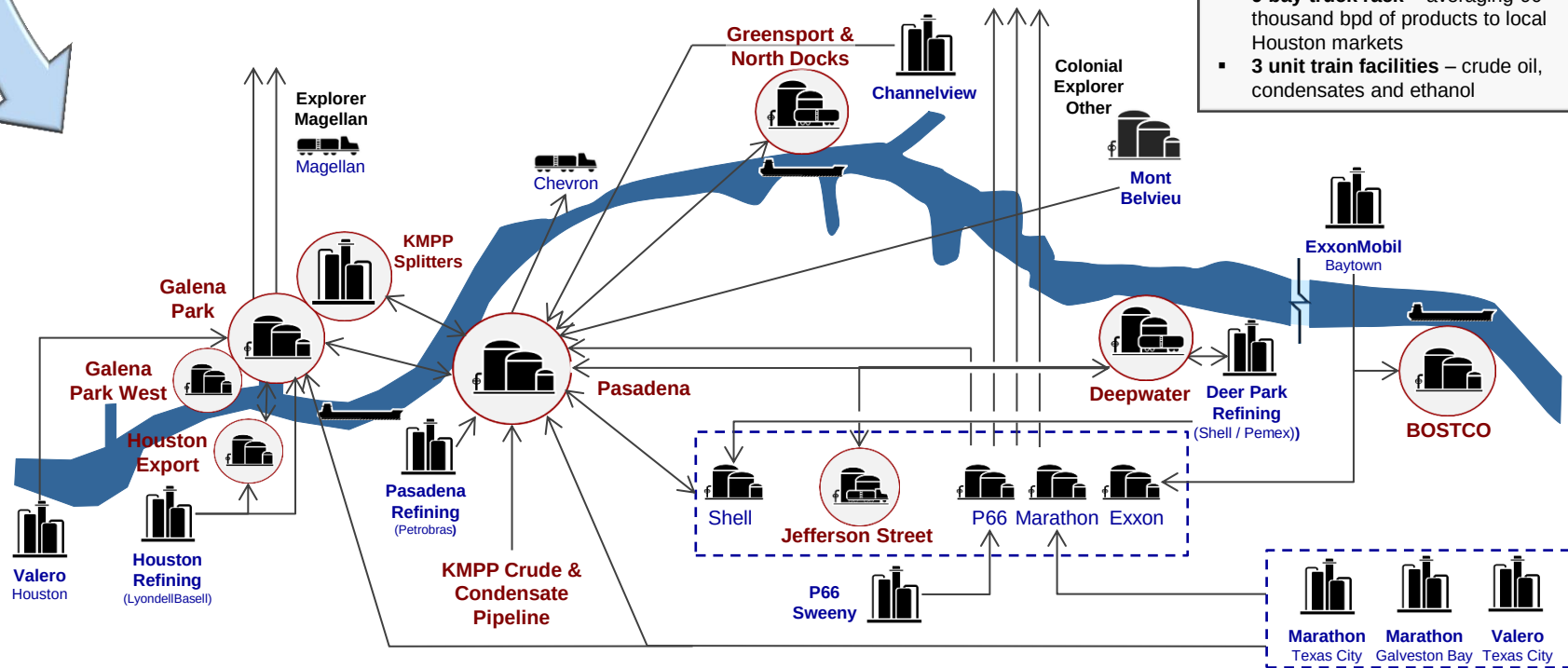
- Tank leases: term-contracted, take-or-pay commitments
- Ancillary fees: ship & barge loading & unloading, blending, transfers

■ Customer Value in in Physical Connectivity

- Multimodal: pipeline, tanker, barge, rail and truck
- Multisource: local refineries, chemical plants, Mont Belvieu, imports

Connectivity

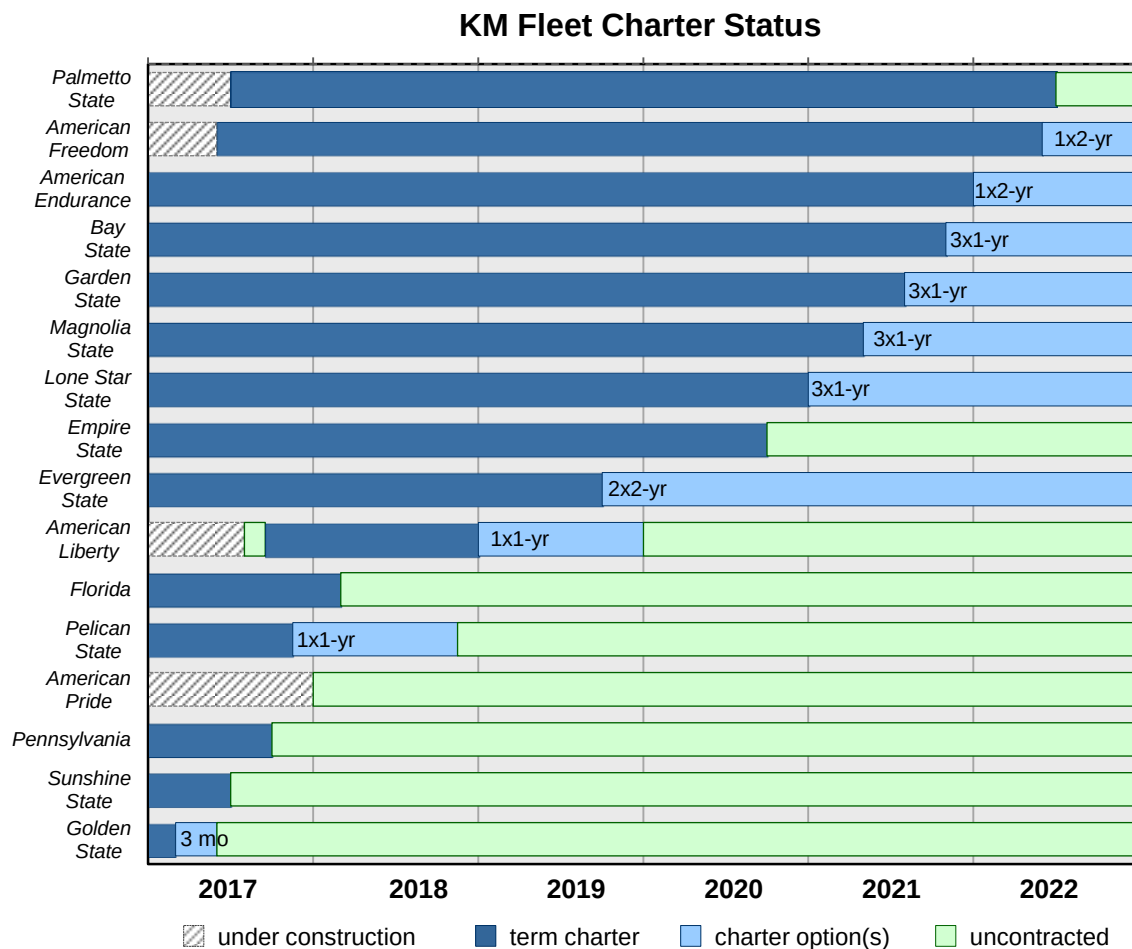
- **20 inbound pipelines** – 10 Houston area refineries and local chemical plants
- **15 outbound pipelines** – Texas, mid-continent and east coast markets
- **14 cross-channel pipelines** – interconnecting the system
- **12 barge docks** – receipt and delivery of products and blendstocks
- **11 ship docks** – serving export markets
- **9 bay truck rack** – averaging 90 thousand bpd of products to local Houston markets
- **3 unit train facilities** – crude oil, condensates and ethanol



Tankers – APT Jones Act Fleet

All of APT's available vessels are sailing under time-charter with limited 2017 exposure

- Average term contract length of 2.8 years across 16-vessels
- 4 new vessels to be delivered in '17
 - American Freedom
 - Palmetto State
 - American Liberty
 - American Pride
- Currently-uncontracted vessels:
 - **\$2.9 million or 0.2% exposure to KMT's 2017 budgeted EBDA**
- Marketing
 - Short-term charters
 - Bundled terminaling services
 - Prompt market voyages



CO₂

Segment Outlook^(a)

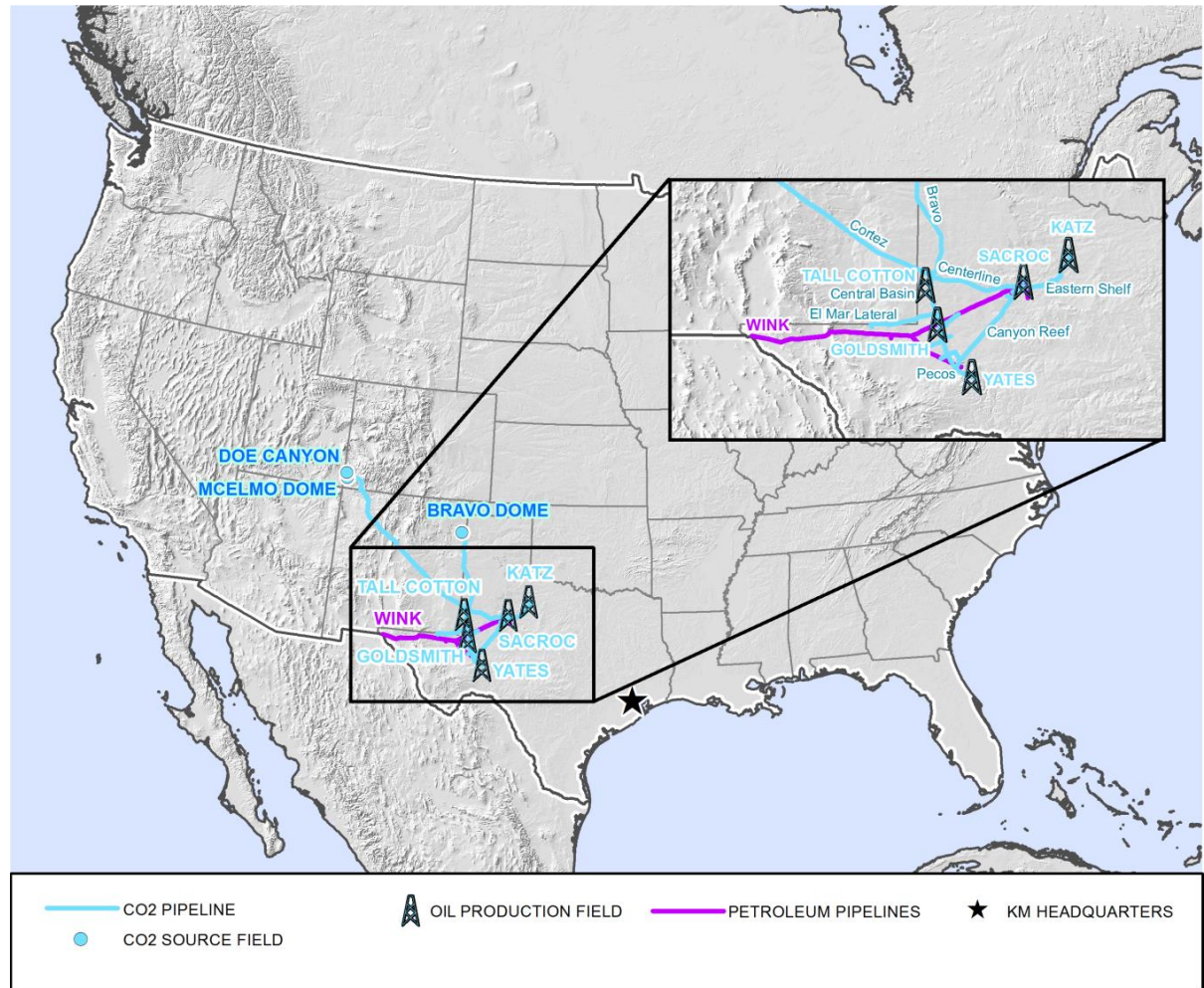
Own and operate best source of CO₂ for EOR

Long-term Growth Drivers:

- Demand for scarce supply of CO₂ drives volume and price
- Expect to maintain current CO₂ production levels with minimal incremental investment
- Billions of barrels of domestic oil still in place to be recovered in the Permian Basin
- >9 billion barrels Original Oil In Place in KM operated fields

Project Backlog:

- Identified growth projects totaling \$0.3 billion and \$1.1 billion in S&T and EOR, respectively, over next five years^(b), including:
 - S&T: Southwest Colorado CO₂ production
 - EOR: SACROC / Yates / Goldsmith / Tall Cotton oil production



(a) EOR = Enhanced Oil Recovery, S&T = Source & Transportation.

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

2017 Projects – Price Sensitivity

AT IRR % vs Oil Price

\$/Bbl	\$50 flat	\$53 flat	\$60 flat	Forward Curve ^(a)
SACROC-Bypass (Long Lateral)	27%	32%	44%	37%
SACROC-Bypass (Sidetrack Lateral)	41%	47%	61%	50%
SACROC Hawaii	14%	19%	30%	22%
Yates Horizontal Drain Hole Program	65%	73%	96%	75%
Tall Cotton Phase 2	32%	36%	43%	38%

■ **Budgeted 2017 operating cash costs:**

- SACROC = \$17.91 /Bbl
- Yates = \$13.14 /Bbl

(a) Forward curve as of 1/18/2017.

KM CO₂ Current Outlook

\$4.7 Billion Cumulative Free Cash Flow Generated Since Inception^(a)

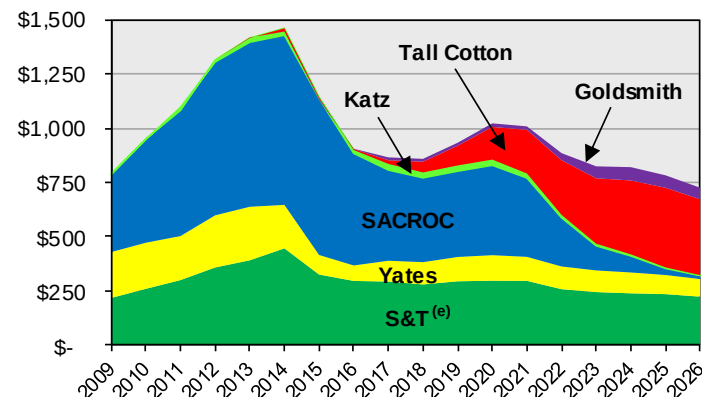
Development Plans 2017-2026

- **SACROC**
 - Continue platform development/redevelopment
 - Expand Bypass Pay/Infill programs
 - Exploit transition zone opportunity
- **Yates**
 - Continue HDH programs and gravity drainage depletion plan
 - Initiate new Westside Waterflood
 - Evaluate HCM pilot
- **Katz**
 - Continue conformance program
 - Optimize flood performance
- **GLSAU**
 - Continue downspacing evaluation
 - Optimize flood performance
- **Tall Cotton**
 - Commence Phase 2 expansion
 - Develop additional project prospects
- **CO₂ S&T**
 - Maintain capacity in existing source fields (McElmo & Doe Canyon)
 - Optimize production and increase efficiency
 - Manage source portfolio to be prepared for increase in demand

■ Total Business IRR (2000-2026): 28.2%

2017-2026	Net BOE ^(b) (MMBOE)	KM Share Capex (\$MM) ^(c)
SACROC	58	\$697
Yates	26	143
Katz	7	61
GLSAU	12	268
Tall Cotton	46	1,006
CO ₂ S&T		442
Total	150	\$2,617

DCF (\$MM)^(e)



(a) Net of invested capital.

(b) Net BOE = Net Crude plus Net NGLs plus Net Residue Gas sold and thereafter divided by 6.

(c) KM Share Capex is inclusive of Capitalized CO₂ and Capitalized OH.

(d) 2017 = Budget, 2017 at \$53/Bbl, 2018 at \$55/Bbl, 2019 at \$60/Bbl, 2020+ at \$65/Bbl; cost metrics based on 2016 run rate; development plans may change in different price scenarios.

(e) CO₂ profits not eliminated from S&T.

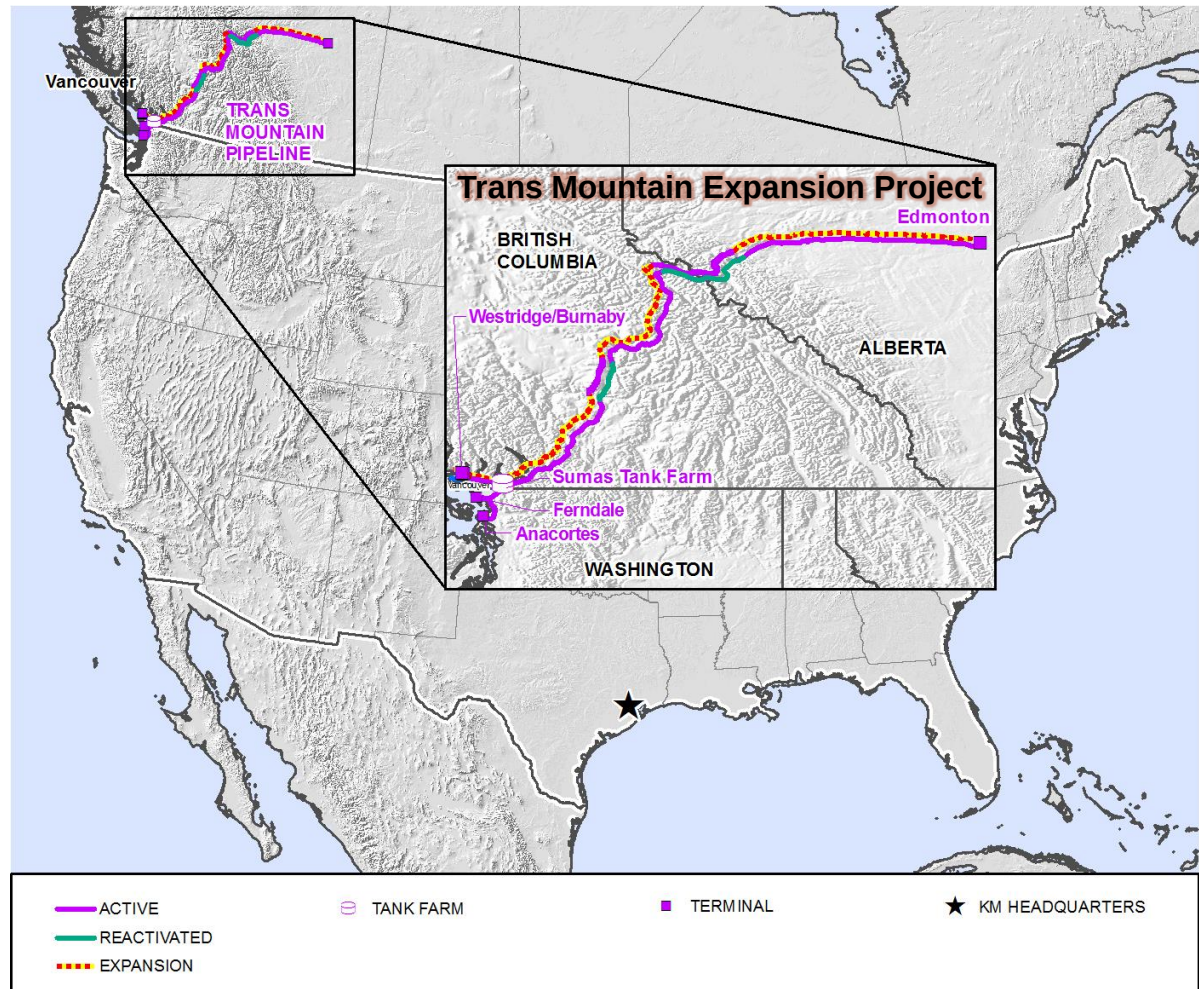
Kinder Morgan Canada

Segment Outlook

Sole oil pipeline from Oilsands to West Coast / export markets

Long-term Growth Drivers:

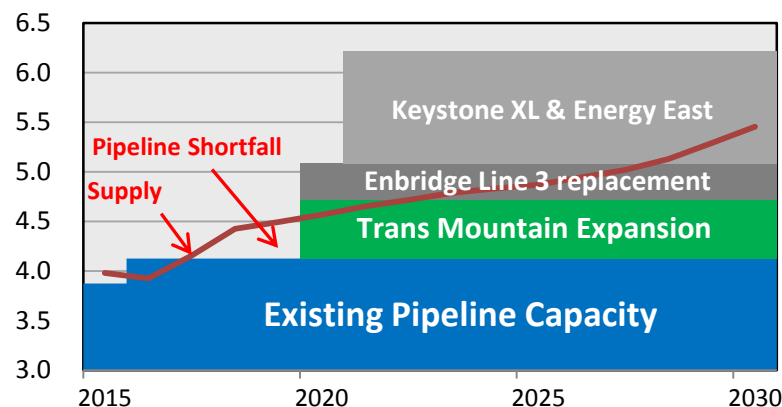
- Expand Oilsands export capacity to West Coast and Asia
 - Following successful regulatory process, major expansion plans under way
 - The Trans Mountain Pipeline Expansion Project (TMEP) more than doubles capacity, from 300 MBbl/d currently to approximately 890 MBbl/d
 - Strong commercial support from shippers with binding long-term 15 and 20 year contracts for 708 MBbl/d of firm transport capacity
 - Expected in-service end of 2019
- Expanded dock capabilities (Vancouver)
 - TMEP will increase dock capacity to over 600 MBbl/d
 - Access to global markets



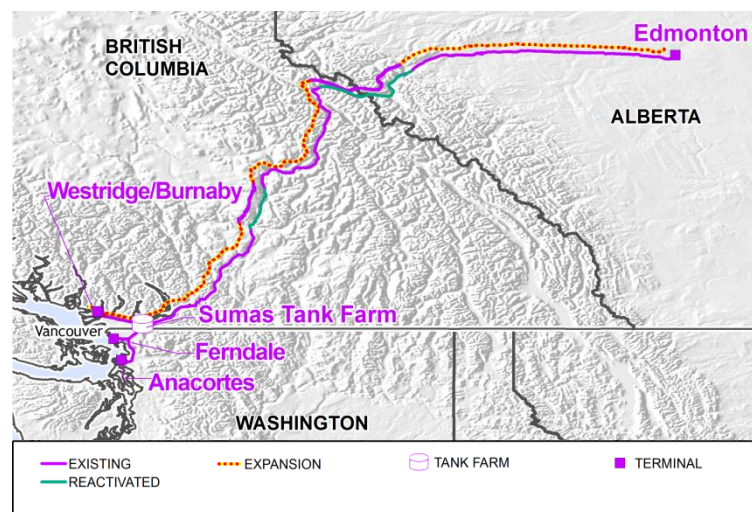
Trans Mountain Expansion Project (TMEP)

- **Expansion to 890 MBbl/d from 300 MBbl/d**
 - 615 miles new pipe; 12 new pump stations
 - 630 MBbl/d tanker export capacity; 3 new berths
 - 20 new tanks
- **13 companies contracted for 708 MBbl/d**
 - 15 & 20 year take-or-pay contracts
 - Commercial terms approved by NEB May 2013
- **Projected Cost**
 - Finalizing cost estimates with contractors
 - Demand remains strong; we expect shippers to remain committed or have other shippers subscribe if final costs are above \$6.8 billion CAD
 - Each \$100mm >\$6.8 billion CAD = ~\$0.07 tariff increase
 - Additional cost pass through protection during construction
 - Substantial development cost protection

Oilsands Supply vs Takeaway Capacity (MMBbl/d)^(a)



Trans Mountain Expansion Project



(a) Canadian Association of Petroleum Producers (CAPP), 2016 Crude Oil Forecast, Markets & Transportation, June 2016, and KM analysis.

Trans Mountain Expansion Project Timeline

2016

- NEB Recommendation May '16
- Federal Approval Dec. '16

2017

- BC Approval Jan. '17
- Cost Review with Shippers Feb. '17
- KM FID 1Q / 2Q 2017
- Begin Construction Sept. '17

2018 – 2019

- Complete Construction, In-Service Dec. '19

Financial Excellence

Kimberly Dang

Chief Financial Officer

Cost & Allocation of Capital

Disciplined Capital Allocation

■ Current:

- Live within cash flow, ration and allocate capital to highest risk-adjusted returns
- Require after-tax, unlevered project returns significantly higher than reasonable estimates of KMI's cost of capital

■ Future:

- Once we have achieved our target leverage of approximately 5.0x net debt/Adjusted EBITDA, we will evaluate several options, including:
 - Investing in high return midstream investment opportunities and/or acquisitions
 - Further paying down debt and/or increasing dividends and/or repurchasing shares
 - Currently, we would expect to increase our dividend, targeting a dividend level that would permit us to cover the equity needs for growth capital with DCF

Self-Reliant Funding

No Need to Access Capital Markets During 2017

(millions)

- **Distributable cash flow can fully cover dividends and growth capital needs**
 - No need to access equity market in 2017
- **Over \$5 billion of liquidity at beginning of 2017 adds tremendous flexibility**
 - No need to access debt market in 2017
- **2017 budget assumes a 50% partner on Trans Mountain to fund its share of expansion capital**
 - Budget does not include any proceeds in excess of the partner's share of expansion capital
 - KMI expects to receive such proceeds, but did not quantify them for budget purposes

Sources	2017 Budget
DCF	\$ 4,456
LT Debt Issuance	2,500
ST Borrowing (net of cash) ^(a)	(36)
Total Sources	\$ 6,920

Uses	2017 Budget
Dividends	\$ 1,120
Growth Capital	3,240
Debt Maturities ^(b)	2,560
Total Uses	\$ 6,920

Note: See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.

(a) Excludes changes in working capital including potential rate case refunds.

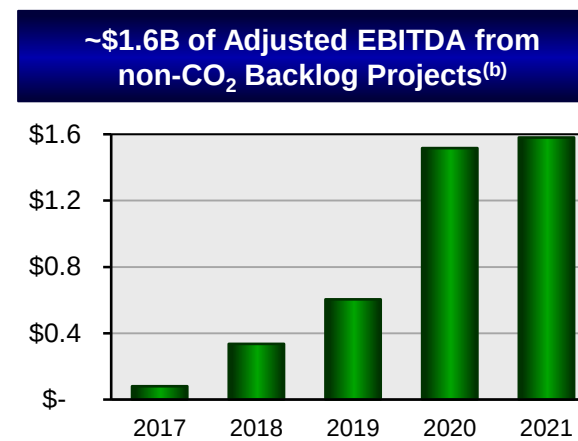
(b) 2017 Budget assumes EP Trust Preferred Securities, which are convertible into the EP merger consideration, are not converted during 2017. Budget also assumes Cora revenue bonds are not put to KMI during 2017. Both are classified as short term debt under GAAP.

5-year Growth Project Backlog^(a)

~\$12 Billion of Attractive, Fee-based Projects

- **World class asset footprint has driven attractive growth opportunities, secured by long-term, fee-based contracts with creditworthy counterparties**
 - ~88% of backlog is for fee-based pipelines, terminals and associated facilities
 - ~\$1.6 billion of annual Adjusted EBITDA expected to be generated from growth projects^(b), excluding CO₂, an approximate 6.7x investment multiple^(c)
 - Target at least 15% unlevered after-tax return to fund CO₂ projects
- **We anticipate achieving a JV or IPO of our Trans Mountain expansion project; backlog currently includes 100% of the project pending further progress**

Segment	Growth Projects ^(a) (\$B)
Natural Gas Pipelines	\$3.5
Products Pipelines	0.3
Terminals	1.4
KM Canada	5.4
Subtotal non-CO ₂	10.6
CO ₂ – S&T ^(d)	0.3
CO ₂ – EOR ^(d)	1.1
Total	\$12.0



(a) 5-year growth project backlog primarily consists of projects in progress for which commercial contracts have been secured. Includes KM's proportionate share of non-wholly owned projects. Includes estimated capitalized corporate overhead of \$0.5 billion. Projects in-service prior to 1/1/2017 excluded.

(b) Estimated first full-year Adjusted EBITDA generated from fee-based pipelines, terminals and associated facilities. Excludes Adjusted EBITDA from CO₂ projects and includes 100% of TMEP. Includes roughly \$150 million of Adjusted EBITDA contribution in the 2017 budget.

(c) Investment multiple calculated as total project cost divided by first full-year expected Adjusted EBITDA.

(d) S&T = CO₂ Source & Transportation. EOR = Enhanced Oil Recovery.

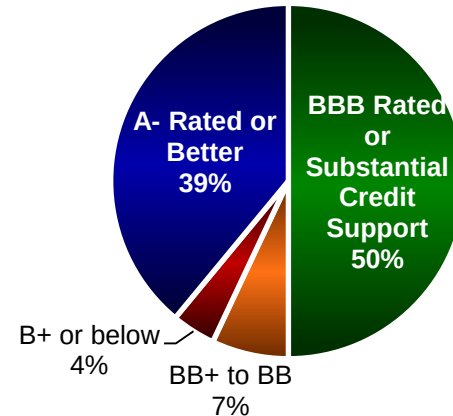
KMI Counterparty Exposure

Strong Customer Credit, Valuable Services Limit KMI's Risk^(a)

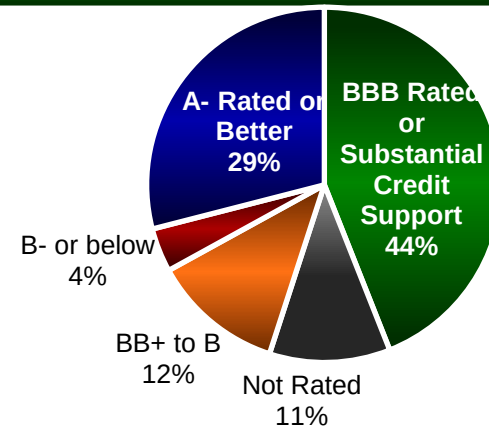
High-Quality, Diversified Customer Base

- KMI's 2016 DCF was impacted by less than \$10 million due to oil & gas bankruptcies
- Greater than 2/3 of revenue^(b) generated by end-users (utilities, LDCs, refineries, chemical, large integrations, etc.)
- KMI's average customer represents less than 0.10% of annual revenue^(b)
- Top 25 customers = ~50% of KMI's revenue^(b)
- Top 218 customers^(c) = ~88% of KMI's revenue^(b)
 - <4% of these revenues from customers with B- or lower rating (net exposure is approximately half^(d) of this)

Top 25 Customers^(b)



Top 218 Customers^(b,c)



(a) Company credit ratings as of 1/18/2017.

(b) Based on budgeted 2017 net revenues, which include our share of unconsolidated joint ventures, net margin for our Texas Intrastate customers, and net of dock premiums for our Canadian customers. Company credit ratings per S&P and Moody's. The charts above use S&P's equivalent rating symbols utilizing a blended rate for split-rated companies.

(c) Customers who individually represent >\$5 million of 2017 budgeted revenue.

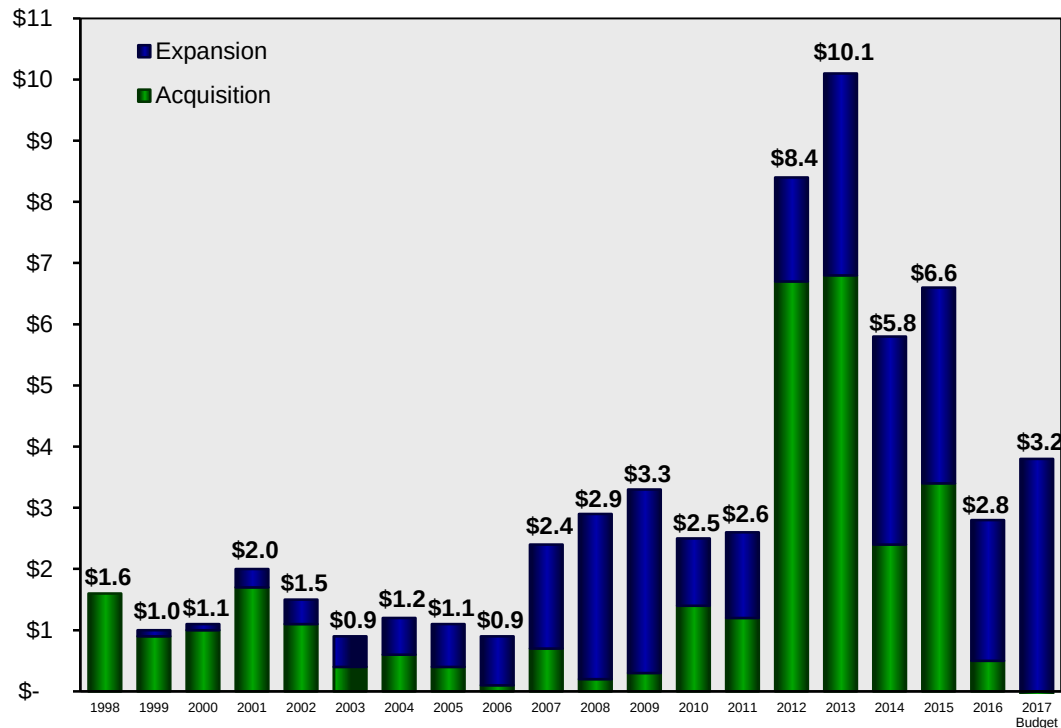
(d) Net exposure is revenues less credit support less market value of capacity.

Capital Invested

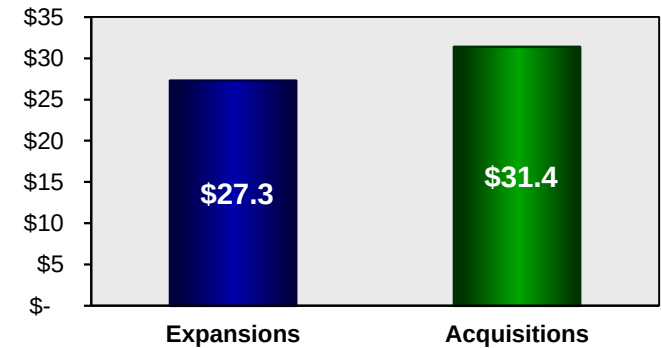
~\$59 Billion of Asset Investment & Acquisitions Since Inception^(a,c)

(\$ in billions)

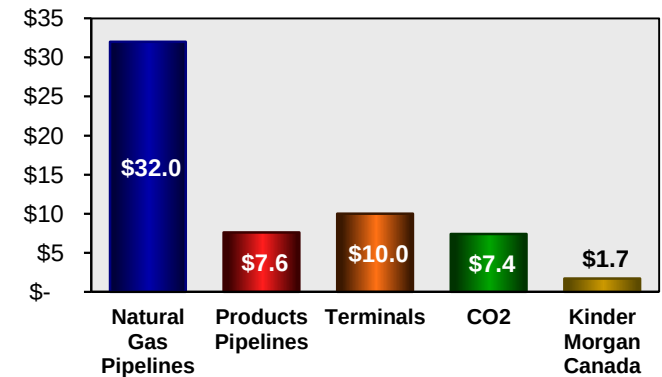
Total Invested by Year^(b,c)



Total Invested by Type^(a,c)



Total Invested by Segment^(a,c)



Note: Includes equity contributions to joint ventures.

(a) 1997-2016; represents investment of KMP (1997-2014), EPB (2013-2014), and KMI (2015-2016).

(b) 1997-2017B; represents investment of KMP (1997-2014), EPB (2013-2014), and KMI (2015-2017B).

(c) Excludes \$2.6 billion and \$1.8 billion for 2016 50% SNG divestiture and 2012 FTC Rockies divestiture, respectively, in Natural Gas Pipelines segment. Excludes \$11.3 billion in EPB asset acquisitions from El Paso prior to KMI's acquisition of El Paso and \$2.0 billion for Citrus acquisition at KMI.

Excludes \$0.3 billion for 2013 divestiture of Express-Platte pipeline system in Kinder Morgan Canada segment.

Excludes \$0.8 billion of Products Pipelines legal and other settlements incurred over the past decade.

However, we do include these impacts in the denominator of our ROI calculation.

Returns on Invested Capital

Segment ROI ^(a) :	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Natural Gas Pipes	13.3%	15.5%	12.9%	13.5%	14.0%	15.5%	16.7%	17.5%	16.9%	14.0%	11.9%	11.9%	11.9%	10.9% ^(b)	10.9% ^(b)	10.3% ^(b,c)	9.9% ^(b,c)
Products Pipelines	11.9	11.8	12.8	12.9	12.4	11.6	11.8	13.2	12.5	13.4	13.7	12.9	12.1	12.4	12.3	12.6	13.1
Terminals	19.1	18.2	17.7	18.4	17.8	16.9	17.1	15.8	15.5	15.1	14.6	14.3	13.5	12.1	11.2	10.2	10.0
CO₂	27.5	24.6	22.0	21.9	23.8	25.7	23.1	21.7	25.4	23.1	25.3	25.9	28.1	25.9	22.8	16.2	12.3
KM Canada	--	--	--	--	--	--	--	11.0	12.1	12.8	13.7	14.1	16.3	14.8	11.5	9.7	10.1
Return on Investment	12.3%	12.7%	12.6%	13.1%	13.6%	14.3%	14.4%	14.1%	14.8%	13.9%	13.5%	13.5%	13.6%	11.9%	11.4%	10.3%	9.7%
Return on Equity	17.2%	19.4%	20.9%	21.7%	23.4%	23.9%	22.6%	22.9%	25.2%	25.2%	24.3%	24.0%	24.0%	21.7%	20.2%	15.9%	13.9%

Notes: Reflects KMP (2000–2012), KMP and EPB (2013–2014) and KMI (2015–2016). A definition of these measures may be found in the Appendix to this presentation.

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

(b) Includes EPB assets. The denominator includes approximately \$1.1 billion in REX capital not recovered in Nov-2013 sale price (i.e., leave behind). Excluding the leave behind cost would increase the Natural Gas Pipes-ROI to 11.3%, 11.2%, 10.5% and 10.1% in 2013, 2014, 2015 and 2016, respectively.

(c) Includes NGPL and Citrus investments.

2017 Guidance

Supported by Diversified, Fee-based Cash Flow

2017 Published Budget

- **DCF of \$4.46 billion^(a)**
 - 2017 DCF per share of \$1.99
 - 2017 declared dividend of \$0.50 per share
 - ~\$3.3 billion of DCF generated in excess of dividend (before growth capex)
- **Growth capital of \$3.2 billion including JV contributions**
- **Adjusted EBITDA of \$7.2 billion^(a)**
- **Expected year-end 2017 net debt/Adjusted EBITDA ratio of 5.4x**
 - Assumes 50% partner on Trans Mountain to fund its share of expansion capital
 - Budget does not include any proceeds in excess the partner's share of expansion capital; KMI expects to receive such proceeds, but did not quantify for budget
 - Assumes 50% partner on Elba Liquefaction to fund its share of expansion capital as well as a reasonable promote payment
- **2017 budget assumes WTI average crude strip price of \$53/Bbl and average natural gas strip price of \$3.00/MMBtu**
 - \$1/Bbl change in oil price = ~\$6 million DCF impact
 - 10¢/MMBtu change in natural gas price = ~\$1 million DCF impact^(b)

See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.

(a) Our non-GAAP measures of DCF and Adjusted EBITDA are before Certain Items and include KM-share of Certain Equity Investee DD&A.

(b) Natural gas sensitivity incorporates current hedges, and assumes ethane recovery for majority of year, constant ethane frac spread, and assumes other NGL prices maintain same relationship with oil prices.

2017 Budgeted Distributable Cash Flow (DCF)

(millions, except per share)

Distributable Cash Flow	2017 Budget	2016 Actual	Change	
			\$	%
Net Income before Certain Items available to common stockholders	\$ 1,458	\$ 1,477	\$ (19)	-1%
DD&A including KMI share of JV DD&A ^(a)	2,651	2,617	34	1%
Book taxes ^(b)	1,043	993	50	5%
Cash taxes ^(c)	(89)	(79)	(10)	13%
Sustaining capex including KMI share of JV sustaining capex ^(d)	(630)	(540)	(90)	17%
Other ^(e)	23	43	(20)	-47%
Distributable Cash Flow available to common stockholders (DCF)	\$ 4,456	\$ 4,511	\$ (55)	-1%
Average adjusted common shares outstanding ^(f)	2,240	2,238	3	0%
DCF per common share	\$ 1.99	\$ 2.02	\$ (0.03)	-1%
Expected/Declared dividend per share	\$ 0.50	\$ 0.50	\$ -	0%
Excess coverage	\$ 3,335	\$ 3,392	\$ (57)	-2%

Note: See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.

(a) Includes KMI share of Certain Equity Investee DD&A, \$392 and \$349 million in 2017 and 2016, respectively.

(b) Includes KMI's share of Certain Equity Investee book taxes of \$108 and \$94 million in 2017 and 2016, respectively.

(c) Includes KMI's share of Certain Equity Investee cash taxes of \$76 and \$76 million in 2017 and 2016, respectively.

(d) Includes KMI share of Certain Equity Investee sustaining capital expenditures, \$112 and \$90 million in 2017 and 2016, respectively.

(e) Primarily non-cash compensation associated with our restricted stock program partially offset by retiree medical and pension contributions.

(f) 2016 includes 8 million average unvested restricted shares that contain rights to dividends. 2017 includes 10 million average unvested restricted shares that contain rights to dividends.

2017 Budgeted Segment EBDA before Certain Items

(millions, except per share)

	2017 Budget	2016 Actual	Change	
			\$	%
Natural Gas Pipelines	\$ 3,877	\$ 4,036	\$ (159)	-4%
CO ₂	880	919	(39)	-4%
Products Pipelines	1,187	1,180	7	1%
Terminals	1,217	1,169	48	4%
Kinder Morgan Canada	191	181	10	6%
Total Segment EBDA before Certain Items	7,352	7,485	(133)	-2%
General and administrative and corporate charges ^(a)	(642)	(665)	23	-3%
Interest, net ^(a)	(1,879)	(1,999)	120	-6%
DD&A	(2,259)	(2,268)	9	0%
Pre-tax income before Certain Items	2,572	2,553	19	1%
Book taxes ^(a)	(935)	(899)	(36)	4%
Net Income before Certain Items	1,637	1,654	(17)	-1%
Noncontrolling interests ^(a)	(23)	(21)	(2)	10%
Preferred stock dividends	(156)	(156)	-	0%
Net Income before Certain Items available to common stockholders	\$ 1,458	\$ 1,477	\$ (19)	-1%
Adjusted Earnings per share				
Average adjusted common shares outstanding ^(b)	2,240	2,238	3	0%
Adjusted EPS ^(c)	\$ 0.65	\$ 0.66	\$ (0.01)	-2%

Note: See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.

(a) Before Certain Items.

(b) 2016 includes 8 million average unvested restricted shares that contain rights to dividends. 2017 includes 10 million average unvested restricted shares that contain rights to dividends.

(c) Adjusted Earnings per share based on net income attributable to common shareholders before Certain Items divided by average adjusted common shares outstanding.

2017 Budgeted Adjusted EBITDA

(millions)

	2017 Budget	2016 Actual	Change	
			\$	%
Adjusted EBITDA				
Segment EBDA before Certain Items	\$ 7,352	\$ 7,485	\$ (133)	-2%
Natural Gas Pipelines JV DD&A	379	349	30	9%
CO2 JV DD&A	7	-	7	n/a
Products Pipelines JV DD&A	12	4	8	200%
Terminals JV DD&A	(6)	(4)	(2)	50%
Subtotal: Segment EBDA before Certain Items plus JV DD&A	7,744	7,834	(90)	-1%
JV book taxes ^(a)	108	94	14	15%
Noncontrolling interests ^(b)	(23)	(21)	(2)	10%
General and administrative and corporate charges ^(b)	(642)	(665)	23	-3%
Adjusted EBITDA	\$ 7,187	\$ 7,242	\$ (55)	-1%

Note: See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.

(a) KM-share of Certain Equity Investee book taxes.

(b) Before Certain Items.

Reconciliation of Financials Presentation, from 4Q '16 Earnings Release to Jan '17 Analyst Day

(millions)

	4Q ER As Reported	Book Tax	Interest Income	Other Segment	As Revised
Natural Gas Pipelines	\$ 4,029	\$ 7	\$ -	\$ -	\$ 4,036
CO ₂	917	2	-	-	919
Products Pipelines	1,185	(5)	-	-	1,180
Terminals	1,133	36	-	-	1,169
Kinder Morgan Canada	161	20	-	-	181
Other	(22)		(3)	25	-
Total Segment EBDA before Certain Items	7,403	60	(3)	25	7,485
General and administrative and corporate charges	(640)	-	-	(25)	(665)
Interest, net	(2,002)	-	3	-	(1,999)
Book DD&A	(2,268)	-	-	-	(2,268)
Pre-tax income	2,493	60	-	-	2,553
Book taxes	(839)	(60)	-	-	(899)
Net Income before certain items	1,654	-	-	-	1,654
Noncontrolling interests	(21)	-	-	-	(21)
Preferred stock dividends	(156)	-	-	-	(156)
Net Income before Certain Items available to common stockholders	\$ 1,477	\$ -	\$ -	\$ -	\$ 1,477

- In our 2017 budget, 2016 10-K and going forward, we have made minor reclassifications to book tax, interest income and the Other segment. The prior periods will be revised for all periods presented going forward. This change was made to reflect these items at the corporate level and to reflect we no longer have an Other reportable segment. We believe this results in a more straightforward presentation.

2017 Budgeted Quarterly Profile

(millions, except per share)

Segment EBDA before Certain Items plus JV DD&A^(a)	Q1	Q2	Q3	Q4	Total
2017 Budget	25%	24%	24%	27%	\$ 7,744
2016 Actual	27%	24%	24%	25%	\$ 7,834
Adjusted EBITDA					
2017 Budget	25%	24%	24%	27%	\$ 7,187
2016 Actual	26%	24%	25%	25%	\$ 7,242
Distributable cash flow (DCF)^(b)					
2017 Budget	26%	23%	23%	28%	\$ 4,456
2016 Actual	27%	24%	24%	25%	\$ 4,511
Adjusted EPS^(c)					
2017 Budget	26%	22%	23%	29%	\$ 0.65
2016 Actual	27%	23%	23%	27%	\$ 0.66

Note: See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.

(a) Includes KMI share of Certain Equity Investee DD&A.

(b) Includes KMI share of Certain Equity Investee DD&A and reduced by KMI share of Certain Equity Investee sustaining capital expenditures.

(c) 2017 Budget represents Adjusted Earnings per share which does not include projections for certain amounts required by GAAP such as ineffectiveness on commodity, interest rate and foreign currency hedges, unrealized gains and losses on derivatives marked to market, and contingent liabilities.

2017 Budget Assumptions/Highlights

Business segments^(a)

- **Natural Gas Pipelines (4%):**
 - Reduction due to full-yr impact of 50% sale of SNG, lower volumes on gathering and processing assets and CIG rate case
 - Partially offset by expansion projects on TGP, Elba Express and NGPL
- **CO₂ (4%):**
 - Decrease driven by price ~\$4/Bbl reduction in weighted average oil price
 - Oil & Gas: oil volumes net essentially flat ~(150) MBbl/d; unhedged price = \$53/Bbl
 - S&T: Cortez expansion, CO₂ volumes ~(1%), CO₂ price ~(2%)
- **Products Pipelines +1%:**
 - Refined products volumes = +1.5%
 - NGL volumes = +5.6%
 - Crude and condensate volumes = (3.3%)
 - +9% in terminal volumes from expansions, full-year BP acquisition impact + 3rd party business growth
- **Terminals +4%:**
 - Growth driven by (i) expansions in the Gulf and Jones Act Fleet, (ii) BP JV and (iii) contract escalations
 - Partially offset by lower rates on expiring Jones Act contracts, sale of 20 bulk terminals and coal contract expiration
- **Kinder Morgan Canada +6%:**
 - Capitalized financing costs
 - CAD/USD 2017 average exchange rate = 0.77x

Interest expense

- **3-mo LIBOR: ~1.15%**
 - Average rate for the year, based on approximate forward curve at time of budget

Cash taxes

- **Not expected to be a U.S. federal cash tax payer in 2017**

(a) Business segment percentage increase/(decrease) is 2016A to 2017B change in Segment EBDA before Certain Items.

2017 Cash Tax Budget Calculation Detail

(millions)

- Not expected to owe material federal income cash taxes until after 2023 (under current tax structure)

	2017 Budget
Segment EBDA before Certain Items	\$ 7,352
Noncontrolling interests ^(a)	(23)
JV earnings from c-corps ^(a)	(200)
JV distributions from c-corps (net of 80% DRD)	38
JV book DD&A (pass-thru entities)	258
General and administrative and corporate charges ^(a)	(642)
Interest, net ^(a)	(1,879)
Book capex items expensed for tax purposes ^(b)	(493)
Tax depreciation from YE 2014 Basis	(4,338)
Tax depreciation for Post-2014 Assets	(1,535)
Other items	(89)
Taxable income (loss)	\$ (1,551)
KMI U.S. federal cash taxes	\$ -
Other cash taxes ^(c)	89
Total cash taxes	\$ 89

Note: See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.

(a) Before Certain Items.

(b) Includes certain sustaining capex, interest during construction, capitalized CO2, intangible completion costs, and capitalized overhead which can be expensed for tax purposes.

(c) Includes cash taxes for (i) our share of Plantation, Citrus, and NGPL (ii) our bulk terminals held in corporate subsidiaries, (iii) Texas margin tax and other state income taxes and (iv) foreign taxes.

2017 Budgeted Sustaining Capital

(millions)

	2017 Budget	2016 Actual	Change
Sustaining capital expenditures^(a)			
Natural Gas Pipelines	\$ 296	\$ 276	\$ 20
CO ₂	14	9	5
Products Pipelines	72	45	27
Terminals	201	160	41
Kinder Morgan Canada	24	26	(1)
Corporate / Other	23	24	(1)
Total sustaining capital expenditures	\$ 630	\$ 540	\$ 90

Note: Before Certain Items.

(a) Includes KMI share of Certain Equity Investee sustaining capital expenditures, \$112 and \$90 million in 2017 and 2016, respectively.

2017 Budgeted Growth Capital

(millions)

- 2017 budgeted growth capital fully funded by internally generated cash flow, with no requirement to access capital markets

	2017 Budget ^(a)	2016 Actual
Growth capital		
Natural Gas Pipelines	\$ 1,762	\$ 1,304
CO ₂ - S&T	31	(2)
CO ₂ - EOR	321	265
Products Pipelines	199	183
Terminals	730	947
Kinder Morgan Canada	197	110
Total growth capital	\$ 3,240	\$ 2,807

(a) 2017 includes JV contributions of \$1,109 million and JV catch-up contributions (Elba Liquefaction, Trans Mountain) of \$575 million.

Credit Ratios and Liquidity^(a)

(\$ in millions)

Leverage metrics	2013	2014	2015	2016	2017 Budget
Net debt ^(b) to Adjusted EBITDA	5.0x	5.5x	5.6x	5.3x	5.4x
Adjusted EBITDA to Interest, net	3.9x	4.1x	3.5x	3.6x	3.8x

Revolver capacity ^(c)	
Committed revolving credit facility	\$ 5,000
Less:	
CP / Revolver borrowing	-
Letters of credit	(160)
Excess capacity	\$ 4,840

Long-term debt maturities ^(d)	
2017	\$ 2,560
2018	2,329
2019	3,820
2020	2,204
2021	2,422

Note: As of 12/31/2016. See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.

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

(b) Debt as defined in footnote above, net of cash and excluding Kinder Morgan G.P. Inc.'s \$100 million preferred stock due 2057.

(c) KMI corporate revolver (maturity in November 2019).

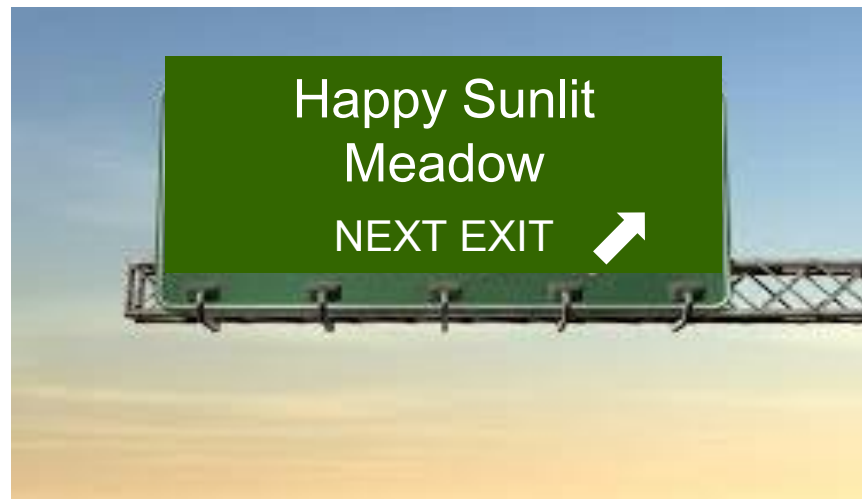
(d) 5-year maturity schedule of annual aggregate long-term debt principal.

Financial Excellence

- Disciplined capital allocation
- Attractive return on investments
- Hedge direct commodity exposure
- Maintain strong balance sheet
- Transparency to investors



Next Stop: Happy Sunlit Meadow



Appendix

Natural Gas Pipelines

Segment Presentation

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Natural Gas Pipelines

Segment Outlook

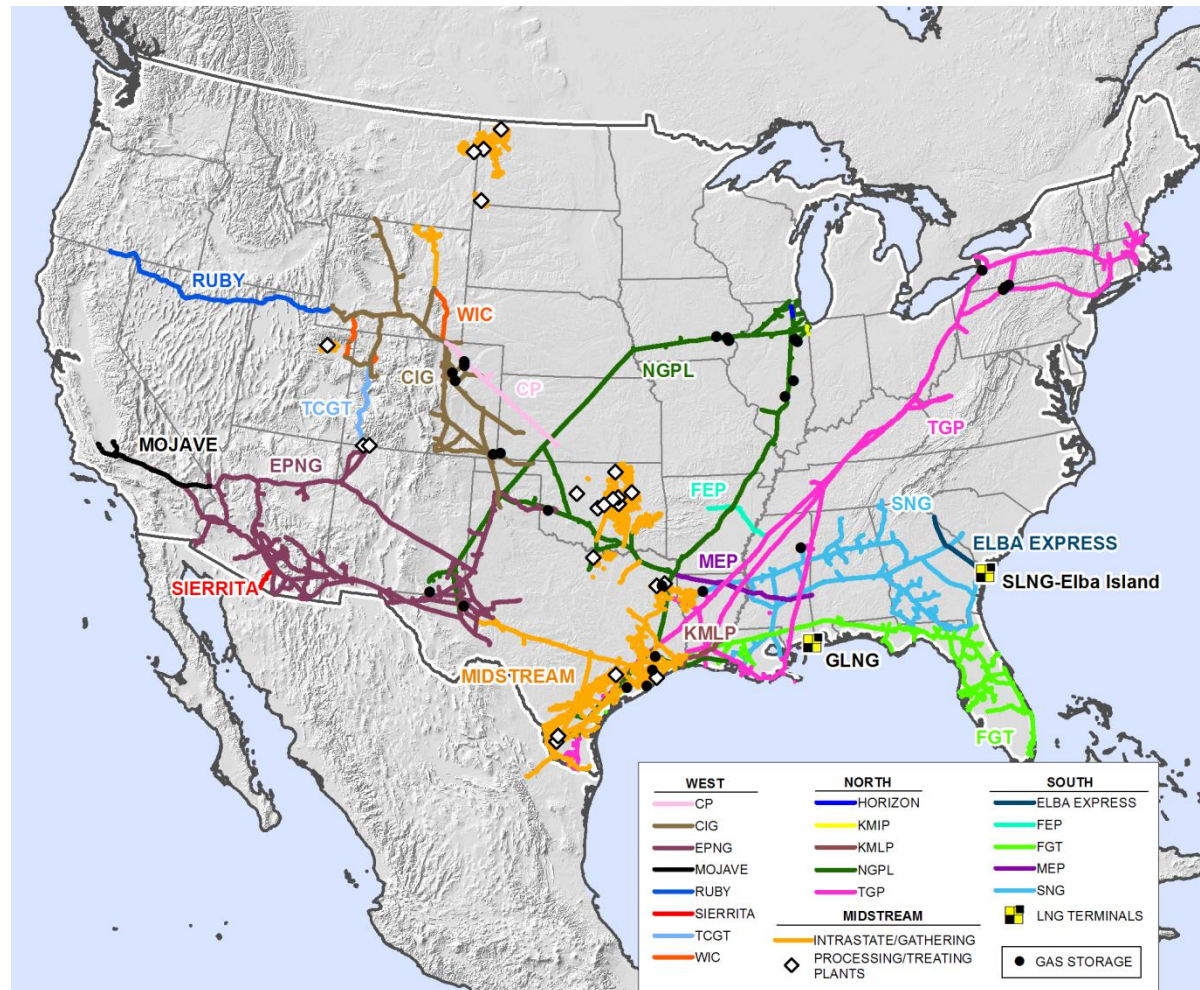
Well-positioned connecting key natural gas resources with major demand centers

Long-term Growth Drivers:

- LNG exports
 - Liquefaction facilities
 - Pipeline infrastructure
- Exports to Mexico
- Gas demand for power generation
 - Coal plant retirements
 - Regional gas-fired power demand growth
 - Backstop for wind and solar
- Industrial demand growth
- Shale-driven expansions / extensions
- Acquisitions

Project Backlog:

- \$3.5 billion of identified growth projects over next four years (2017-2020)^(a), including:
 - LNG liquefaction (Elba Island)
 - Transport projects supporting LNG liquefaction, including Elba Express
 - Expansions to Mexico border
 - TGP North-South projects



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

Drivers of Future Growth

LNG Exports

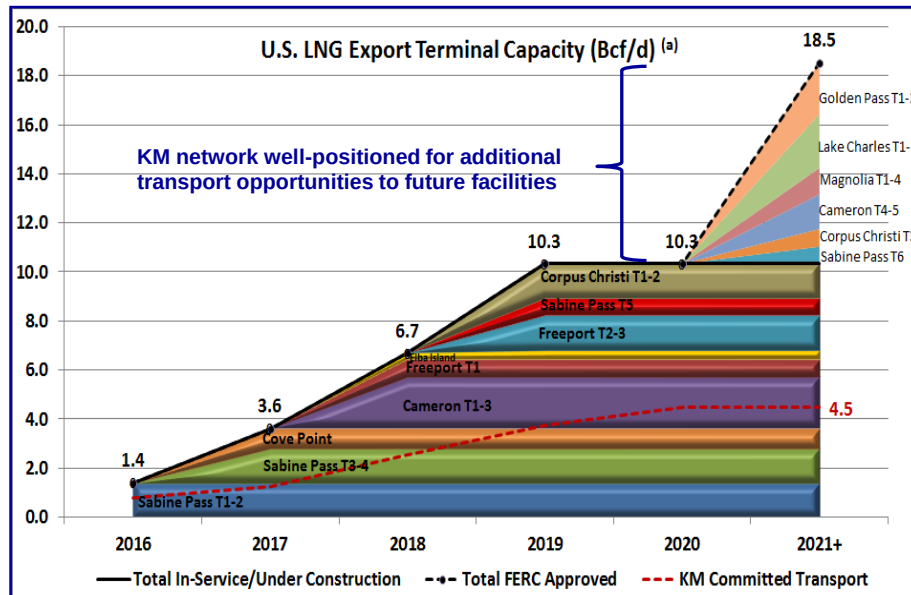
■ LNG Export Opportunity^(a)

- 18.5 Bcf/d of FERC approved projects
- 10.3 Bcf/d of projects under construction
- 9.8 Bcf/d of additional projects pending approval

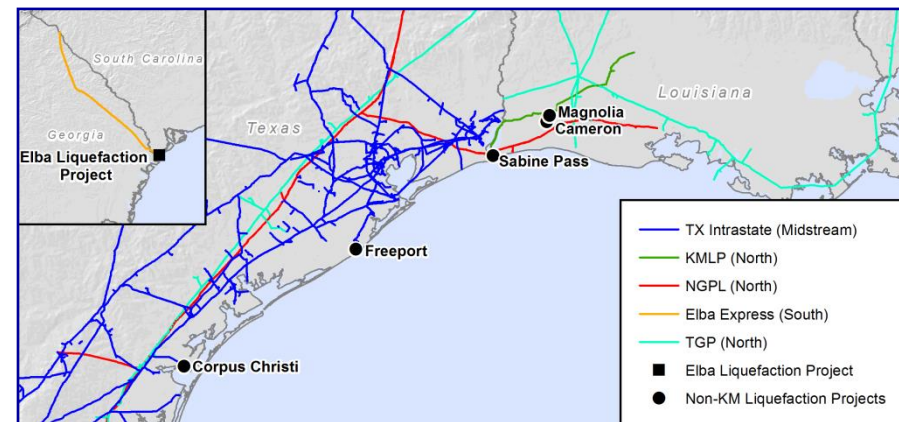
■ Elba Liquefaction – KM facility at Elba Island, GA

■ LNG Transport

- 4.5 MMDth/d of contracted transport capacity
- Total capital of \$981 MM
- Avg. contract term: 19 years
- Seven active projects on five KM pipelines



KM Asset	KM Project/Transportation (Terminal)	Contracted Capacity (MDth/d)	In-Service Date	KM Capital (\$MM)
NGPL	Firm Transport (Sabine Pass)	550	In-Service	N/A
EEC	EEC for Shell (Elba Island)	436	2/2017-11/2018	\$102.2
TGP	SW Louisiana Supply (Cameron)	900	2/2018	\$178.5
NGPL	Gulf Coast Southbound (Corpus Christi)	385	4Q/2018	\$106.1
Intrastate	TX Intrastate Crossover (Corpus Christi/Freeport)	590	1Q-3Q 2019	\$182.1
TGP	Lone Star (Corpus Christi)	300	7/2019	\$133.8
KMLP	Sabine Pass Expansion	600	4Q/2019	\$151.3
KMLP	Magnolia LNG Expansion	700	4Q/2020	\$127.0



(a) FERC as of 1/5/17, industry and KM analysis.

Liquefaction at Elba Island

Elba Liquefaction Company (ELC) / SLNG



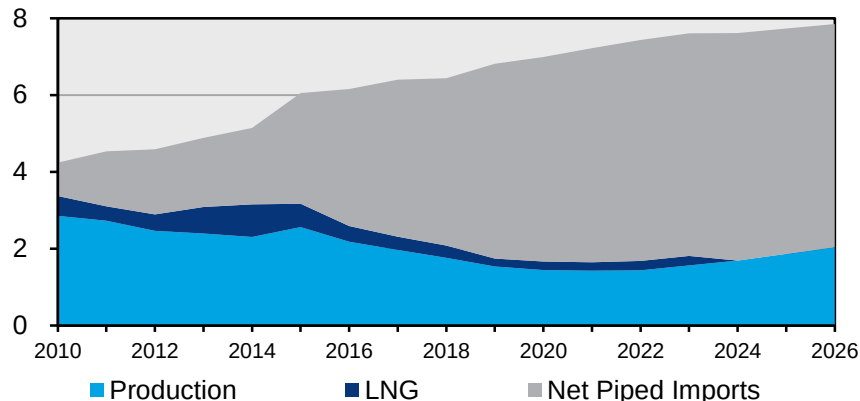
- **Capacity:**
 - LNG output capacity equivalent to 350 MMcf/d
- **Capital (100%):**
 - ELC: \$1,436.4 MM
 - SLNG: \$ 433.8 MM
- **Phased In-service: Mid 2018 through early 2019**
- **Project Scope:**
 - Facilities for liquefaction (10 modular units)
 - Ship loading facilities; boil-off gas compression
- **Avg. Contract Term: 20 years**
- **Current Status:**
 - FERC certificate issued June 2016
 - FERC denied requests for rehearing Dec 2016
 - Shell has committed to entire capacity of facility, as well as Elba Express expansion
 - DOE FTA and non-FTA authorizations received
 - Construction underway
- **Major Milestones:**
 - JV negotiations for ELC are ongoing

Drivers of Future Growth

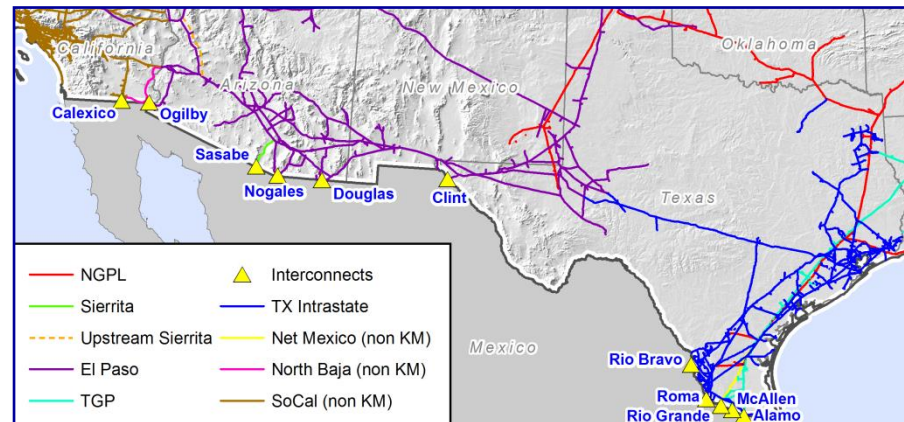
Kinder Morgan Delivers ~76% of U.S. Exports to Mexico

- Exports to Mexico are forecasted to increase by 2.0 Bcf/d to 5.6 Bcf/d by 2021^(a)
- KM deliveries to Mexico ~2.8 MMDth/d^(b) through 17 interconnects (12 direct & 5 indirect)
 - KM up 20% from 2015; 76% of 2016 U.S. total
 - Well positioned to serve incremental demand through extensive network connected to multiple prolific supply basins
- KM projects and new long term commitments for export to Mexico entered into since 2013:
 - Capacity: ~2.4 MMDth/d
 - Capital: ~\$667 MM

Mexico Gas Supply (Bcf/d)^(a)



KM Asset	KM Project / Transportation (Shipper)	Contracted Capacity (MDth/d)	In-Service Date	KM Capital (\$MM)
Sierrita	Sierrita Gas PL (CFE)	200	10/2014	\$64.1
EPNG	S. Mainline Exp. (CFE)	471	10/2014 - 7/2020	\$134.8
TX Intra	Mier Monterrey (MexGas/Others)	225	12/2014	\$94.0
EPNG	Transport (CFE)	85	2014 / 2017	NA
TGP	S. System Flex (MexGas)	500	1/2015 - 12/2015 - 10/2016	\$229.6
TGP	Transport (MexGas)	100	1Q 2016	NA
TX Intra	Crossover Project ^(c)	527	9/2016	\$125.0
EPNG	Transport (GIGO)	20	4Q 2016	NA
EPNG	Trans. (Mexicana de Cobre)	9	4Q 2016	NA
Sierrita	Sierrita Gas PL Expansion (CFE)	230	4/2020	\$19.8



(a) Wood Mackenzie, Fall 2016 North America Natural Gas Long-Term Outlook, December 2016.

(b) 2016 calendar year average.

(c) Commitment to part of larger Crossover project designed to support LNG Exports, Gulf Coast Industrial demand and Exports to Mexico.

Drivers of Future Growth

Other

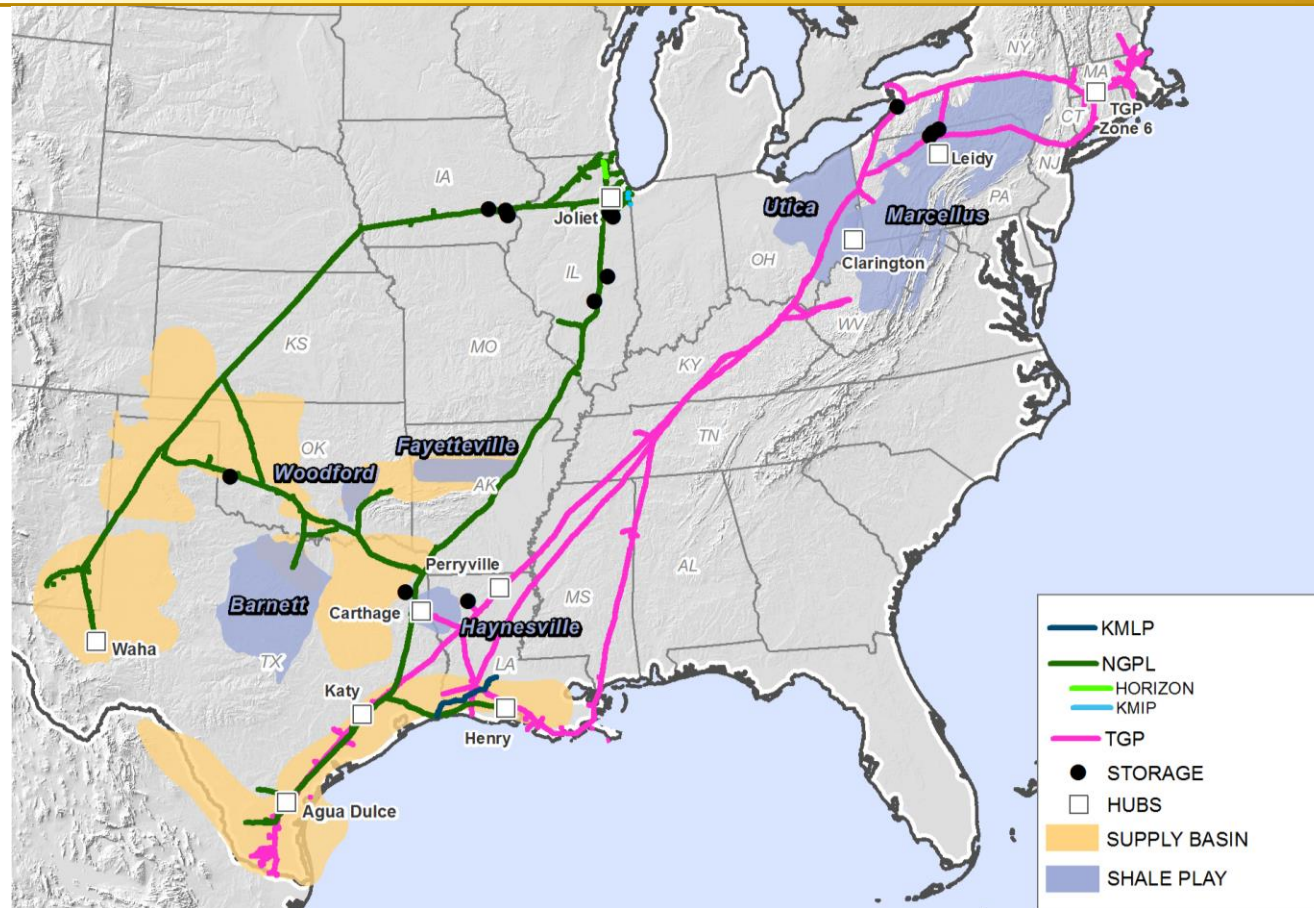
- **Power generation**
 - Continued trend of generators procuring firm transportation and storage services to ensure their performance in ISO capacity reliability programs
 - Increasing need for transportation, storage and ancillary services to backstop variable renewable generation
- **New opportunities in growing export markets**
 - Storage and ancillary services in support of LNG liquefaction and exports to Mexico
- **Industrial growth markets**
 - Well positioned to serve >\$170 billion announced U.S. natural-gas related petrochemical expansion projects (\$76 billion completed or under construction)^(a)
- **Residential and commercial markets**
 - Small to moderate expansions and extensions off our existing footprint to support LDC growth around the country, especially New England
- **Supply-based expansions/extensions**
 - Expansions and extensions off existing network to support growth as demand balances with existing supply

(a) American Chemistry Council, *Trade: A Pro-Growth, Pro-Competitiveness Agenda for Chemical Manufacturing factsheet*, December 21, 2016.

North Region Assets

Growth Drivers:

- **Power Demand:** New infrastructure required for growing gas-fired power generation
 - Gas-fired power demand growth in the Northeast and Midwest
 - Economic/environmental replacement of coal/oil generation
- **LNG Export:** New infrastructure requirements drive opportunity
 - 6 Bcf/d^(a) of additional demand from 4 approved LNG liquefaction projects near TGP, NGPL and KMLP
 - Additional indirect throughput for KM pipes in the region
- **Mexico Exports:** Demand on TGP and NGPL to deliver shale volumes to Mexico
- **Marcellus/Utica:**
 - TGP provides access for Marcellus and Utica shale plays to Gulf Coast and Northeast markets
 - NGPL provides access to premium Midwest LDC and Gulf Coast markets
- **Industrial Demand:** TGP and NGPL positioned to supply new industrial plants
- **Storage Demand:** Significant storage capacity for new power demand, Mexico and LNG variability
- **NE/Canada Demand:** New gas service and conversions in New England and Canada



Asset (KM ownership shown if not 100%)	Miles	Capacity (Bcf/d)	Storage (Bcf)	Avg. Remaining Contract Term (Yrs)	Effective Date of Next Rate Case
Tennessee Gas Pipeline (TGP)	11,800	10.2	104	7.3 / 3.7 ^(b)	NA
Natural Gas Pipeline Co. of America (NGPL, 50%)	9,100	6.9	288	4.8 / 2.9 ^(b)	Pending
Kinder Morgan Louisiana Pipeline (KMLP)	135	2.2	-	0 ^(c)	NA

(a) KM analysis.

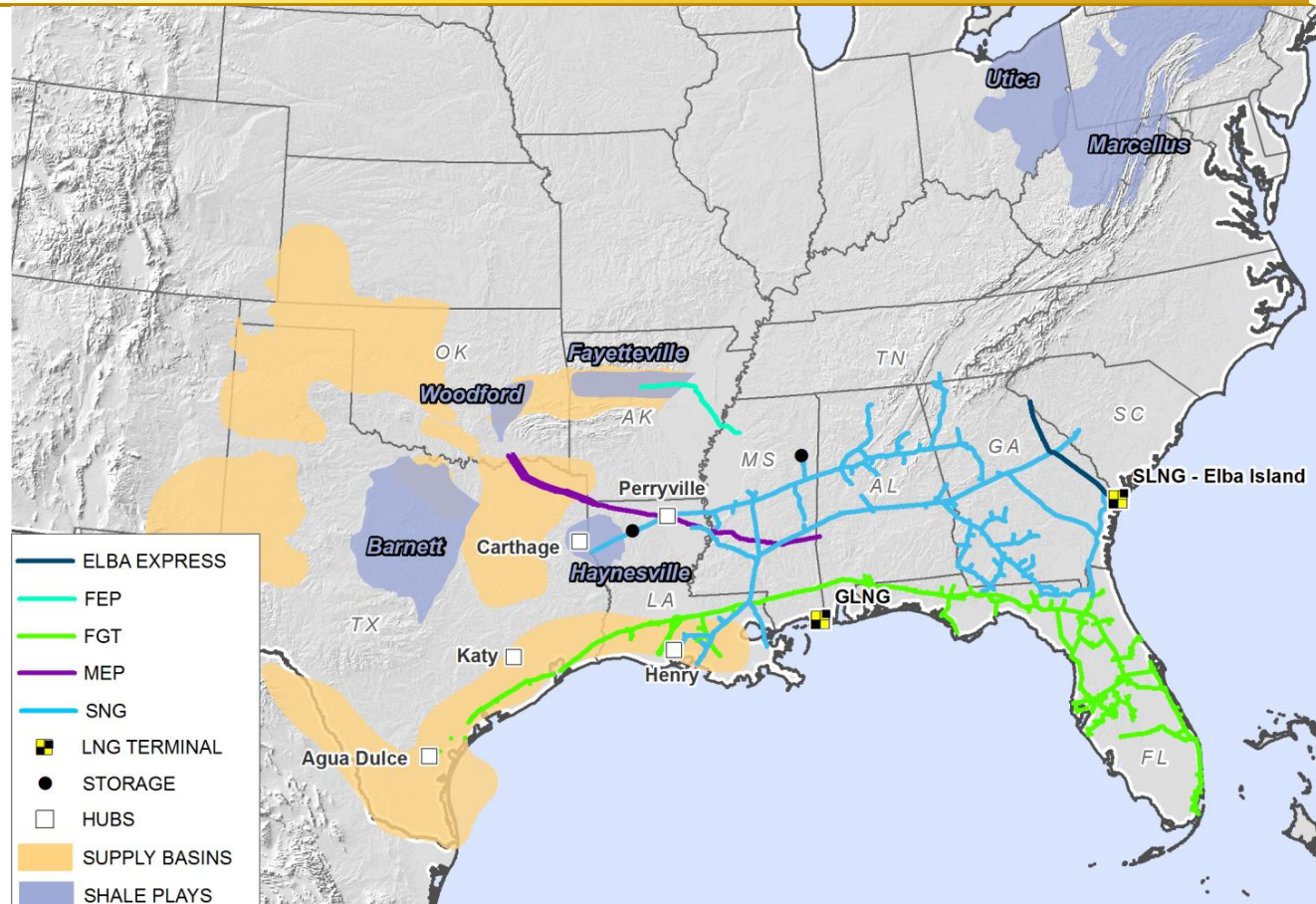
(b) Transport / Storage.

(c) Anchor shippers exercised buyout option in 2015.

South Region Assets

Growth Drivers:

- **LNG Export:** KM participating in LNG liquefaction infrastructure
 - Elba Island terminal liquefaction facilities under construction
- **Expansion:** Additional SNG expansion opportunities to support growth in service territory of JV partner-Southern Company
- **Power Demand:** New infrastructure required for growing gas-fired power generation
 - Gas-fired power demand growth in the Southeast
 - Economic/environmental replacement of coal/oil generation
- **Industrial Demand:** SNG positioned to supply new industrial plants
- **Marcellus/Utica:** SNG provides markets for Marcellus and Utica shale plays to Southeast and Gulf Coast markets
- **Storage Demand:** Significant storage capacity for new power demand and LNG variability



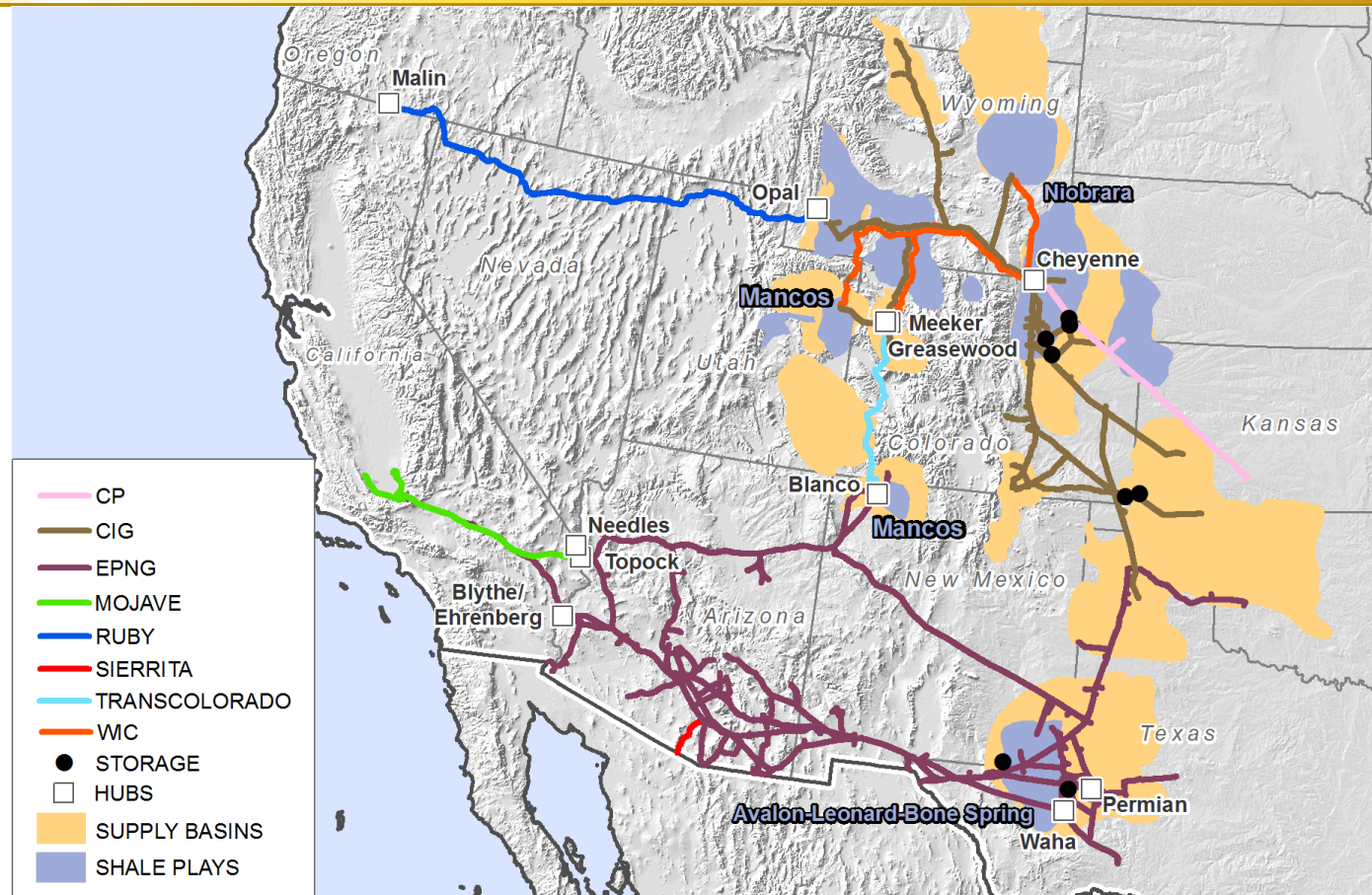
Asset (KM ownership shown if not 100%)	Miles	Capacity (Bcf/d)	Storage (Bcf)	Avg. Remaining Contract Term (Yrs)	Effective Date of Next Rate Case
Southern Natural Gas (SNG, 50%)	6,900	4.1	68	5.4 / 1.7 ^(a)	9/1/2018
Elba Express (EEC)	200	1.0	-	20.8	NA
Midcontinent Express (MEP, 50%)	510	1.8	-	2.3	NA
Florida Gas Transmission (FGT, 50%)	5,300	3.6	-	9.9	NA
Fayetteville Express (FEP, 50%)	185	2.0	-	4.2	NA
Elba Island LNG (SLNG)	-	1.7	11.5	15.8	NA
Gulf LNG (GLNG, 50%)	5	1.5	6.6	14.8	NA

(a) Transport / Storage.

West Region Assets

Growth Drivers:

- **Mexico Exports:** Leading connectivity for incremental supply to Mexico
 - 5.6 Bcf/d of exports to Mexico forecast by 2021^(a)
 - 2016 YTD deliveries to Mexico:
 - West Region: 1.1 MMDth/d
 - KM Total: 2.8 MMDth/d
- **Power Demand:** Renewable energy growth promotes gas-fired power backstop
 - Economic/environmental replacement of coal & oil plants
- **Storage Demand:** Significant storage capacity with superior connectivity
- **Supply Access:** Access to all Rockies basins with diverse geology and hydrocarbon mix; opportunities for new builds and conversions
- **LNG Exports:** Potential for 1 Bcf/d of demand from West Coast projects near Ruby



Asset (KM ownership shown if not 100%)	Miles	Capacity (Bcf/d)	Storage (Bcf)	Avg. Remaining Contract Term (Yrs)	Effective Date of Next Rate Case
Ruby (50%)	680	1.5	-	5.8	NA
El Paso Natural Gas (EPNG), incl. Mojave	10,600	5.6	44	5.5	NA
Colorado Interstate Gas (CIG), incl. Young Gas Storage (YGS, 47.5%)	4,350	5.2	43	5.7 / 5.9 ^(b)	03/1/2022
TransColorado (TCGT)	310	1.0	-	1.3	NA
Wyoming Interstate (WIC)	850	3.9	-	4.3	Pending
Cheyenne Plains (CP)	410	1.2	-	2.9	NA
Sierrita (35%)	60	0.2	-	22.8	NA
Keystone Gas Storage	12	0.4	6	2.3	NA

(a) Wood Mackenzie, Fall 2016 North America Gas Long-Term Outlook, December 2016.

(b) Transport / Storage.

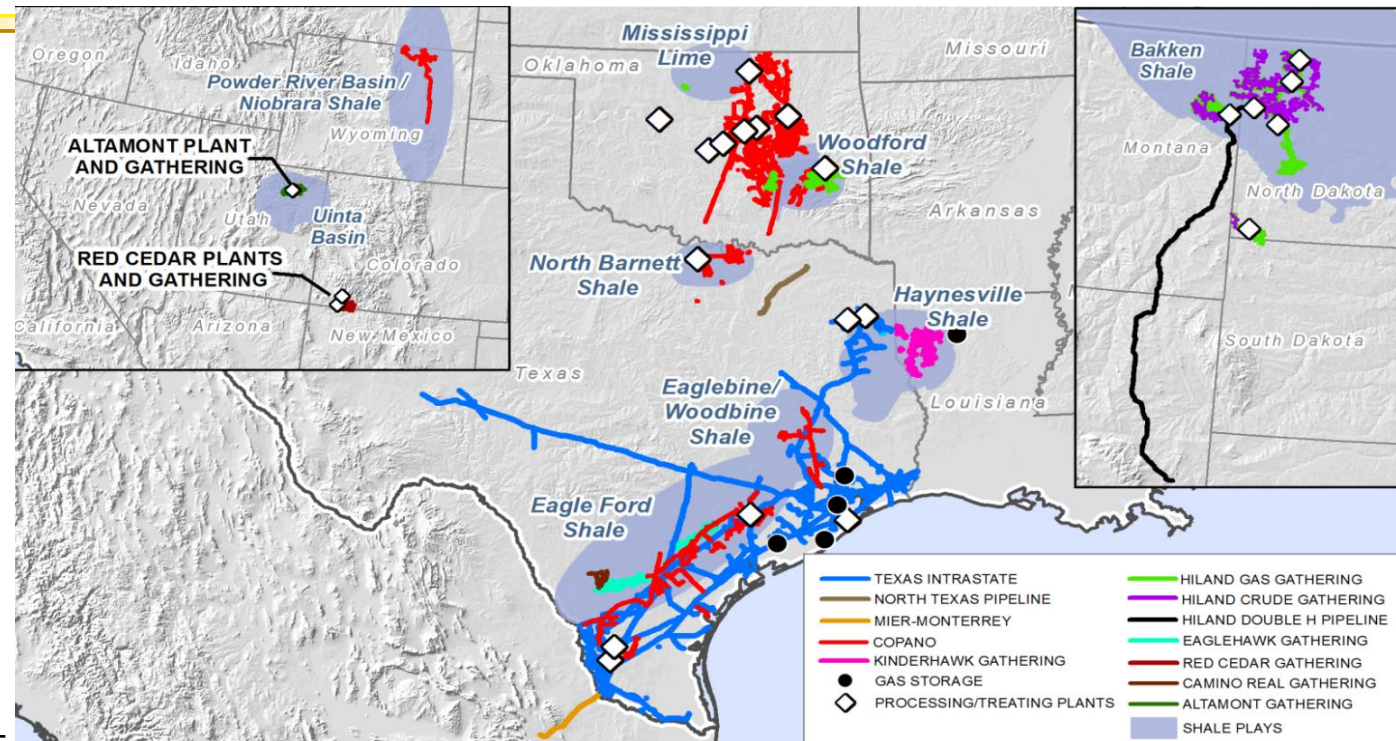
Midstream Assets

Growth Drivers:

- **Mexico Exports:** Leading connectivity for increased deliveries into Mexico (Texas Intrastate)
- **Industrial Demand:** Well positioned to serve >\$170 B announced U.S. pet-chem. expansion projects, \$76 B completed or under construction (Texas Intrastate)
- **LNG Exports:** Approximately 1 Bcf/d of additional demand from 1 approved LNG project along the Gulf Coast near Texas Intrastates
- **Storage Demand:** Significant storage capacity and connectivity enable premium services, including load balancing to power and end use markets (Texas Intrastate)
- **Acquisitions:** expansions/acquisitions around extensive gathering and processing footprint

Commodity Price Exposure (2017):

Processing and Gas Price Exposures (DCF impact in millions)		
	Gross (excl. hedges)	Net (incl. hedges as of 1/9/17)
Price Change		
\$1/Bbl WTI	\$1.8	\$0.6
1% NGL ^(a) /crude ratio	\$1.2	\$0.4
¢1/gal ethane frac spread ^(b)	\$1.1	\$0.5
\$0.10/Dth gas ^(c)	\$2.0	\$0.7



Asset (KM ownership shown if not 100%)	Miles	Capacity	Storage	Treating Capacity	Processing Capacity	Avg. Remaining Transport Contract Term (Yrs)
KMTP / Tejas	5,650	6.4 Bcf/d	136 Bcf	1,680 GPM	510 MMcf/d	5.5
North Texas Pipeline	80	330 MMcf/d				16.6
Mier-Monterrey	90	650 MMcf/d				11.2
Endeavor (40%)	100	150 MMcf/d				2.8
Kinderhawk Gathering	500	2.0 Bcf/d		2,600 GPM		Life of Lease
Eagle Hawk Gathering (25%)	590 – gas	1.2 Bcf/d – gas				Life of Lease
Red Cedar Gathering (49%)	410 – condensate	220 MBbl/d – condensate	60 MBbl			
Camino Real Gathering	750	700 MMcf/d		4,600 GPM		4.5
Altamont Gathering	70 – gas	150 MMcf/d – gas				5.8
Copano	70 – oil	110 MBbl/d – oil	20 MBbl			6.2
Hiland (Williston Basin)	1,350	80 MMcf/d			80 MMcf/d	3.8
Treating - Leased Units	6,780 – gas	4.3 Bcf/d – gas				3.7
	430 – liquid	115 MBbl/d – liquid		4,100 GPM	1.3 Bcf/d	6.8
	2,000 – gas	305 MMcf/d – gas		80 GPM	200 MMcf/d	13.4
	1,480 – oil	240 MBbl/d – oil				7.1
Treating - Leased Units 54 plants in service – Amine; 82 plants in service – MRU; 11 plants in service – Dew Point						

(a) Excluding ethane.

(b) Unfavorable impact can be limited by reducing ethane equity volumes through operational changes and contractual elections.

(c) Assumes constant ethane frac spread vs. natural gas prices.

Contracted Capacity and Term by Region

Region		Contracted Capacity	Average Term Remaining	
North	Storage	355 Bcf	3 yr, 1 mo	Interstate Transport Contracts Avg. = 6 yr, 3 mo
	Transport	19.7 Bcf/d	6 yr, 2 mo	
South	Storage	52 Bcf	1 yr, 8 mo	
	Transport	13.5 Bcf/d	7 yr, 8 mo	
	LNG	18 Bcf	15 yr, 5 mo	
West	Storage	45 Bcf	5 yr, 4 mo	
	Transport	17.4 Bcf/d	5 yr, 2 mo	
Midstream	Purchases	2.5 Bcf/d	2 yr, 0 mo	
	Sales	3.0 Bcf/d	2 yr, 6 mo	
	Storage	101.8 Bcf	2 yr, 5 mo	
	Transport ^(a)	5.1 Bcf/d	6 yr, 10 mo	
	Processing	1.8 Bcf/d	6 yr, 1 mo	

■ **Net annual incremental re-contracting exposure (KM share)^(b):
(% of \$7.7 billion Total KMI Segment EBDA)**

Region	2018	2019
North	(1.1%)	(0.1%)
South	(0.2%)	(0.7%)
West	(0.1%)	(0.1%)
Midstream	(0.3%)	(0.1%)
Total GPG	(1.7%)	(1.0%)

(a) Gathering contracts not included.

(b) Negative figures represent unfavorable re-contracting exposure. Includes transportation and storage contracts.

Natural Gas Segment

Projects Placed Into Service - 2016

Region	Asset	Project	In-service Date	Capacity	Capital, KM Share (\$MM)	EBITDA (\$MM)
North	TGP	South System Flexibility (MexGas)	Oct 2016	150 MDth/d	178.8	
		Exelon (Venango)	Dec 2016	60 MDth/d	5.6	
	NGPL	Chicago Market Expansion	Nov 2016	238 MDth/d	34.6	
South	SNG/EEC	MGAG Expansion	Dec 2016	1.7 MDth/d	1.8	
		SNG Expansion	Dec 2016	242 MDth/d	89.0	
		EEC Expansion (non-Shell)	Dec 2016	175 MDth/d	94.0	
West	EPNG	Ramsey North expansion (Anadarko)	Apr-Oct 2016	450 MDth/d	3.5	
Midstream	Texas Intrastate	Well / Market Connects	Throughout 2016	Various	7.6	
		TX Intrastate Crossover Project	3Q 2016	1,000 MDth/d	125.0	
	Gathering/ Other	Roosevelt Cryo plant	1Q 2016	45 MMcf/d	74.3	
		NGL stabilization exp. / Lavaca slug catcher mods	1Q 2016	1.5 Mbb/d	10.6	
		Other System Expansions / Well Connects	Throughout 2016	Various	89.4	
Total Gas Pipeline Group					714.2	158.6

Natural Gas Segment

Project Backlog – North Region

Asset	Board Approval	Customer Execution	Project	Capital, KM Share (\$MM)	Capacity	In-service Date	Project Status
TGP	Completed	Completed	Connecticut Expansion	93.1	72 MDth/d	11/2017	Agreement reached re compensation for MA state lands. Pursuing final state permits. Construction to begin June 1.
			Susquehanna West	156.5	145 MDth/d	11/2017	Complete FERC Notice to Proceed received 1/4/17. Construction to begin 1Q 2017.
			Triad	68.9	180 MDth/d	11/2017 - 6/2018	FERC Certificate received 12/30/16. Construction to begin 1Q 2017. Test gas in 4Q 2017; fully in service by mid-2018.
			Southwest Louisiana Supply (Cameron LNG)	178.5	900 MDth/d	2/2018	FERC Certificate received 12/15/16. Construction to begin 1Q 2017.
			Broad Run Expansion	452.5	200 MDth/d	6/2018	FERC Certificate received 9/2016. Construction to begin 1Q/2Q 2017.
			Orion	140.7	135 MDth/d	6/2018	FERC Environmental Assessment issued 8/2016. FERC Certificate anticipated by 1Q 2017.
			Lone Star (Cheniere Corpus Christi LNG)	133.8	300 MDth/d	7/2019	TGP FERC application filed 8/2016. LNG terminal construction underway.
KMLP	Completed	Completed	Sabine Pass Expansion	151.3	600 MDth/d	4Q 2019	KMLP FERC application filed 12/2016. LNG terminal construction underway.
			Magnolia LNG Expansion	127.0	700 MDth/d	4Q 2020	Magnolia received DOE Non-FTA export authorization, 12/2016.
NGPL	Pending	Pending	Power Plant Interconnect Project	4.3	120 MDth/d	12/2017	Final contract execution and NGPL Board approval pending.
			LDC Interconnect Project	5.9	75 MDth/d	11/2018	Final contract execution and NGPL Board approval pending.
	Completed	Completed	Gulf Coast Southbound Expansion	106.1	385 MDth/d	4/2017, 4Q 2018	FERC Certificate expected 9/30/17 for 4Q 2018 in-service volume.
Total North Region				1,618.6	EBITDA = \$271.8 MM		

Natural Gas Segment

Project Backlog (Cont'd) – South, West & Midstream

Asset	Board Approval	Customer Execution	Project	Capital, KM Share (\$MM)	Capacity	In-service Date	Project Status
SNG	Completed	Completed	Fairburn Expansion Project	120.6	329-341 MDth/d	10/2018	Open season completed. FERC filing Feb 2017.
EEC	Completed	Completed	EEC Expansion for Elba Liquefaction	102.2	436 MDth/d	2/2017, 9/2018, 11/2018	Initial 191 MDth/d expected in-service Feb 2017.
ELC / SLNG	Completed	Completed	Elba Liquefaction	732.6	357 MDth/d	7/2018 - 3/2019	Initial FERC Notice to Proceed received 10/17/16. FERC denied requests for rehearing on 12/9/16. DOE approved non-FTA exports on 12/16/16. Construction underway. JV negotiations are ongoing.
			SLNG Terminal for Elba Liquefaction	433.8		7/2018	
Total South Region				1,389.2	EBITDA = \$195.6 MM		
EPNG	Completed	Completed	EPNG - Enviro Water Interconnect and Lateral Expansion	2.7	5 MDth/d	1/2017	Construction nearing completion.
			EPNG - South Mainline Expansion (formerly Upstream Sierrita)	132.4	271 MDth/d	4/2017, 7/2020	Open season closed, FTSA executed.
			EPNG - Wink Station Expansion	3.4	71 MDth/d	11/2017	Finalizing interconnect agreement.
Sierrita	Completed	Completed	Sierrita Gas Pipeline Expansion	19.8	230 MDth/d	4/2020	Completed intial governmental outreach meetings.
Total West Region				158.3	EBITDA = \$36.2 MM		
Texas Intrastate	Completed	Completed	TX Intrastate Combined Crossover Project	182.1	1,000 MDth/d	3Q 2019	Phase I placed in service 3Q '16.
		Partial	Market / Supply connects	17.8	Varies	2017	Expansion capex for market / supply connects.
Gathering / Other	Completed	Partial	Williston Basin Oil (Hiland)	49.2	Varies	2017 - 2018	Crude oil well connections and system expansions.
			Williston Basin Gas (Hiland)	35.6	Varies	2017 - 2018	Gas well connections and system expansions.
			Other System Expansions and Well connects	56.2	Varies	2017	Expansions / extensions of existing gathering systems.
Total Midstream				340.9	EBITDA = \$40.7 MM		
Total Natural Gas Pipelines segment				3,507.0	EBITDA = \$544.3 MM		

New Firm Transport Capacity

Firm Transport Capacity Commitments by Capacity Type

Dec. 1, 2013 to Present	Existing Capacity (MDth/d)	Repurposed Capacity (MDth/d)	New Committed Capacity (MDth/d)	Total Capacity (MDth/d)	Capital, KM Share (\$MM)	Wtd Avg. Contract Term (Yrs)
North	797	180	4,691	5,668	2,212	17.2
South	4	0	417	421	129	14.5
West	1,051	0	751	1,802	163	13.5
Midstream	70	0	750	820	284	17.2
Total Gas Pipeline Group	1,922	180	6,609	8,711	2,787	16.3
2016-only	343	180	327	850	125	15.2

Firm Transport Capacity Commitments by Customer Type / End-use Market

Dec. 1, 2013 to Present	LDC / End-user (MDth/d)	Producer (MDth/d)	Mexico (MDth/d)	LNG (MDth/d)	Total Capacity (MDth/d)
North	910	2,173	600	1,985	5,668
South	421	0	0	0	421
West	126	861	815	0	1,802
Midstream	70	160	0	590	820
Total Gas Pipeline Group	1,527	3,194	1,415	2,575	8,711
2016-only	660	61	129	0	850

Products Pipelines

Segment Presentation

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Products Pipelines

Segment Outlook

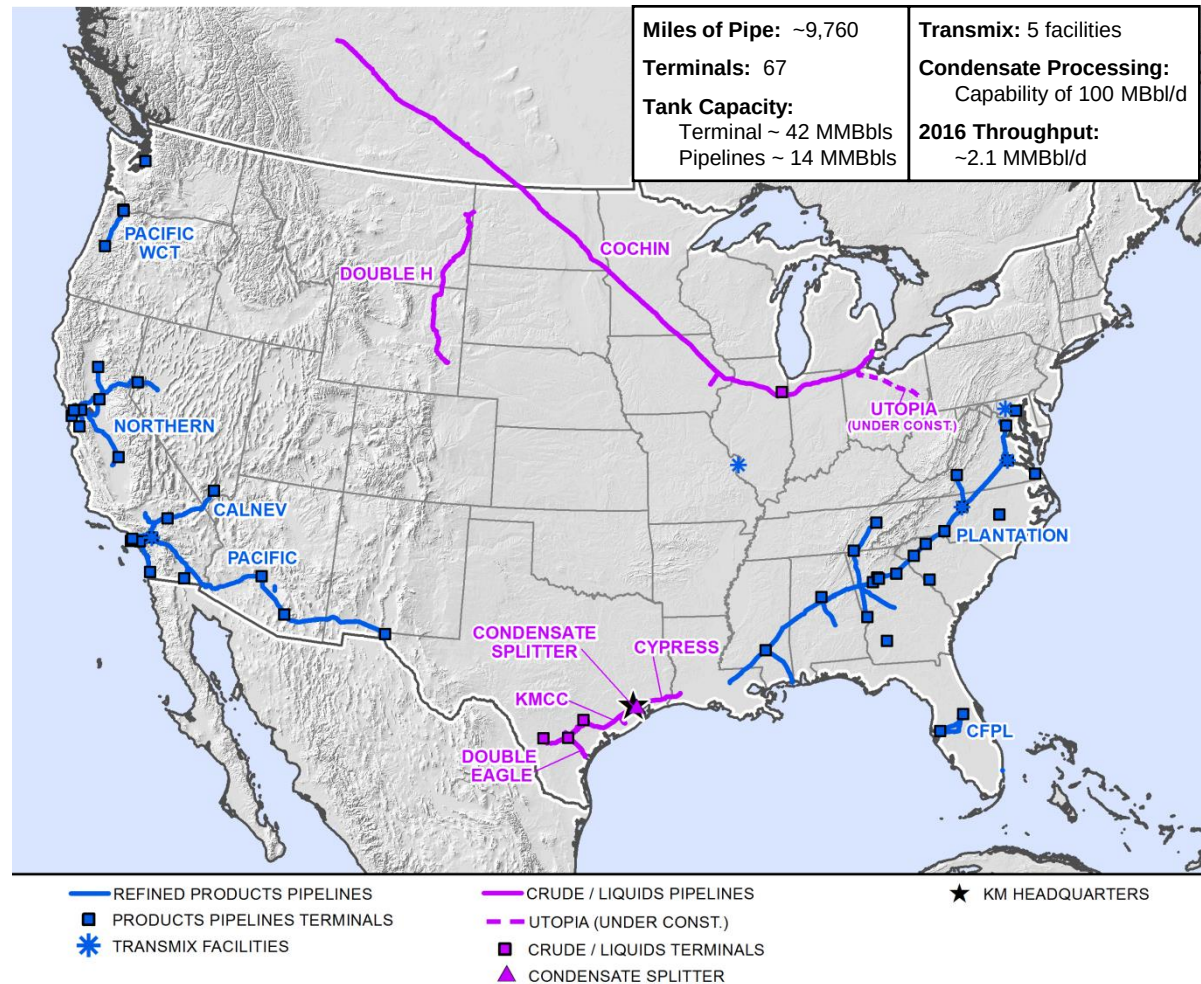
Stable, Strategic Assets

Long-term Growth Drivers:

- Increased demand for refined products volumes
- Development of shale play liquids transportation and processing (e.g. Utopia and KMCC / splitter)
- Tuck-in acquisitions (e.g. KM Phoenix Terminals)
- Expansion of refined products pipeline systems and Terminal Networks
- Repurposing portions of existing footprint in different product uses

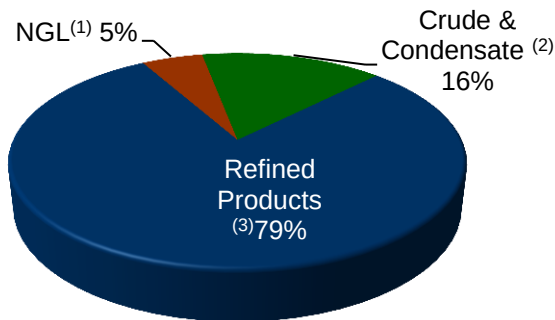
Project Backlog:

- \$318 million of identified growth projects over next two years^(a) (first year total Adjusted EBITDA \$22.8 million^(b)), including:
 - Utopia
 - Multiple refined products Terminating and Bio Fuels projects

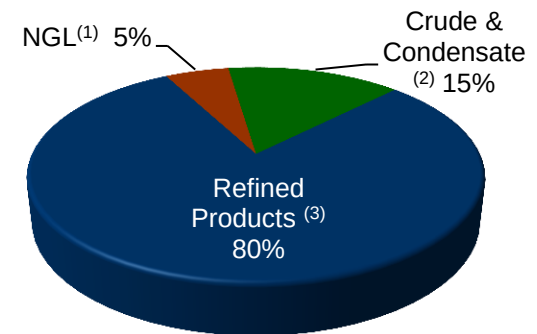


Volumes / Revenues

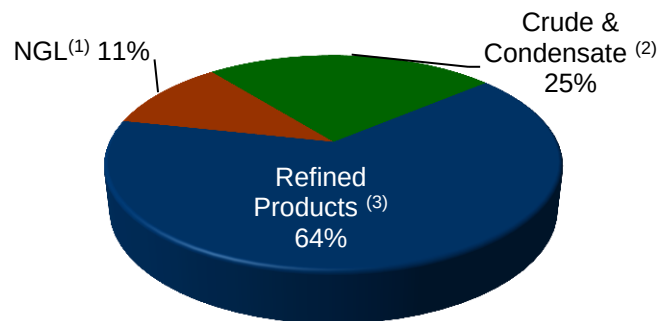
2016 Actual Volumes^(a)



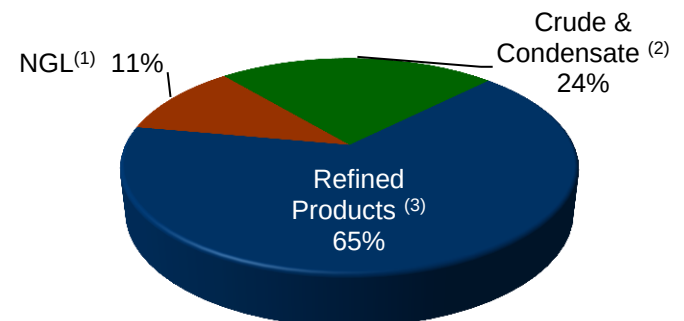
2017 Plan Volumes^(a)



2016 Actual Revenues^(b)



2017 Plan Revenues^(b)



(a) Pipeline throughput volumes only (not including terminal volumes).

(b) Includes terminal revenues:

(1) NGL: Cochin, Cypress, Utopia.

(2) Crude & Condensate: KMCC, Double Eagle, Double H, Splitter (Terminal).

(3) Refined Product: SFPP, Calnev, Central Florida, Plantation, Parkway, KMAP, SE terminal, Transmix(Terminal), West coast Terminal.

Volumes / Markets^(a)

Refined Products^(b):

- **2016:** Refined products volumes 1,651 MBbl/d, up 0.3% vs. 2015
 — Gasoline up 1.2%, diesel down 3.5%, jet fuel up 1.7%
- **2017:** 1,676 MBbl/d budgeted, 1.5% up vs. 2016
 — Budget volume sensitivity: 1% change = \$7.5M

NGLs:

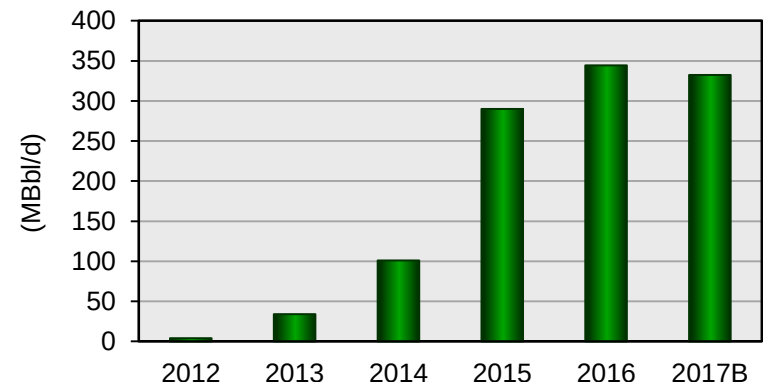
- **2016:** NGL volumes 108 MBbl/d, up 2.7% vs. 2015
 — Drivers: higher volumes on Cochin Pipeline
- **2017:** Budgeted volume to be up 5.6% vs. 2016
 — Drivers: Increased demand on Cochin; no forecasted turnaround in 2017 at Cypress Pipeline terminus

Crude/ Condensate:

- **2016:** Crude / condensate vol. 323 MBbl/d, up 18.3% vs. 2015
 — Drivers: expansion projects on KMCC/ Double Eagle and acquisition of Double H pipeline
- **2017:** 312 MBbl/d budgeted, down 3.3% vs. 2016
 — Drivers: Decreased production from the Eagle Ford

Product Group	KM-share Volumes ^(b)		Revenues ^(b)	
	2016 Actual	2017 Plan	2016 Actual	2017 Plan
Refined Products	1,651 MBbl/d	1,676 MBbl/d	\$1,013K	\$1,039K
NGL	108 MBbl/d	114 MBbl/d	\$172K	\$176K
Crude & Condensate	323 MBbl/d	312 MBbl/d	\$391K	\$376K
Total	2,083 MBbl/d	2,103 MBbl/d	\$1,576K	\$1,591K

Crude/ Condensate Volume Ramp^(c)



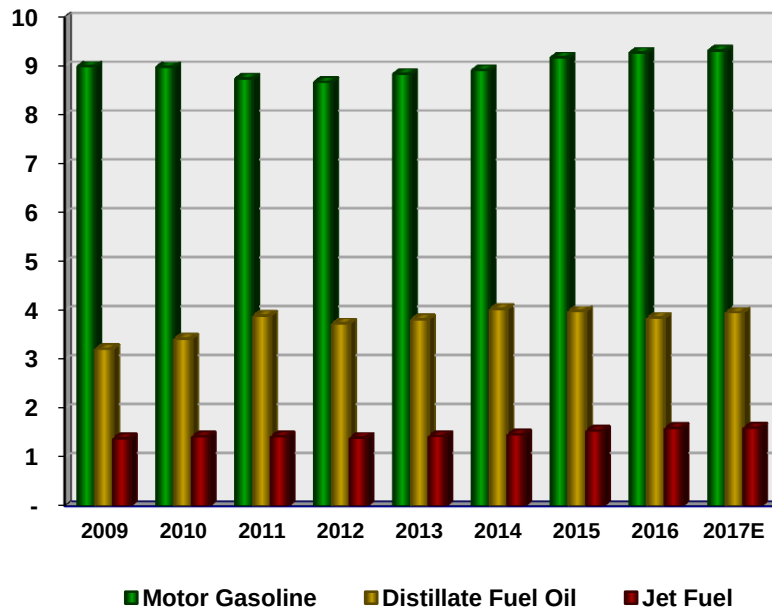
(a) All volumes reflect KM-share for joint ventures.

(b) Parkway divested July 2016. Parkway volumes and revenue not included in 2016 and 2017.

(c) Combined throughput of KM crude/ condensate pipelines: KMCC, Double Eagle and Double H.

Historical Demand and 2017 EIA Outlook^(a)

U.S. Refined Products Consumption (MMBbl/d)



U.S. Refined Products Demand Outlook

	2015	2016	2017E
Mogas	1.1%	0.7%	0.7%
Distillate	-3.5%	3.2%	1.6%
Jet Fuel	3.6%	0.5%	0.1%
Total	0.1%	1.4%	0.8%

FERC Tariff Index

	Jul'15–Jun'16	Jul'16–Jun'17	Jul'17–Jun'18
FERC Rate Increase	4.58%	-2.01%	0.20% ^(b)

(a) EIA, Table 4a. U.S. Crude Oil and Liquid Fuel Supply, Consumption, and Inventories and Figure 15 U.S. Liquids Fuel Consumption Growth, January 2017.

(b) BLS, January 2017 release; expected rate increase based on current regulatory information, based on PPI FG +1.23%.

KMCC / Double Eagle

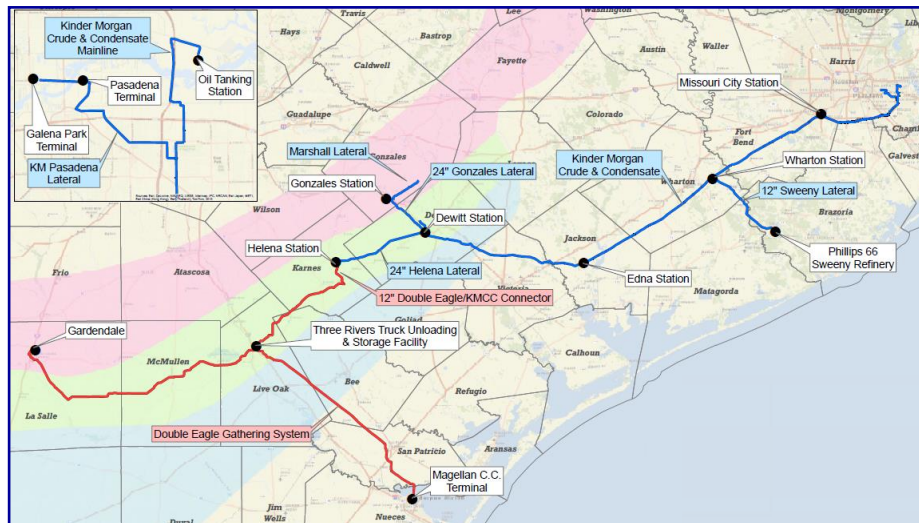
Location, Contracts, Connectivity

Kinder Morgan Crude & Condensate (KMCC)

- Capacity = 300 MBbl/d, expandable to 360 MBbl/d; Approximately 90% of current capacity committed
- Provides Eagle Ford producers access to Houston Ship Channel (Refineries, Export Opportunities), KM Splitter, Phillips 66 Sweeny Refinery

Double Eagle Pipeline

- Capacity 100 MBbl/d; 75% of capacity committed; 50/50 JV w/ Magellan
- Provides Eagle Ford producers access to Magellan Corpus Christi Terminal and KMCC

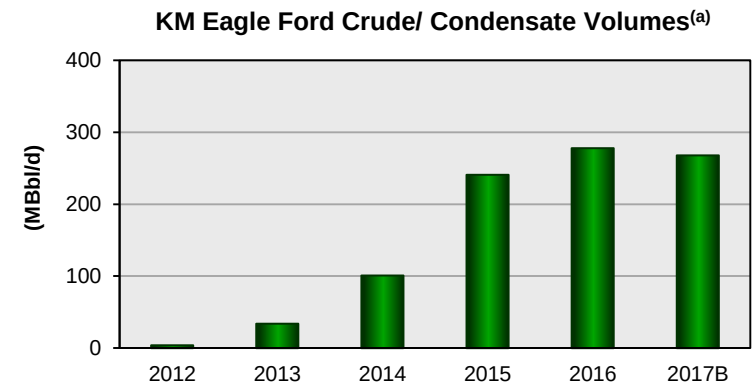


2016 Milestones

- KMCC / Double Eagle volumes grew 15.3% year over year as the full year impact of expansion projects and new customer commitments were realized
- KMCC volumes grew from 2015 to 2016, despite a 22% decline across the Eagle Ford^(b)

2017 Plans

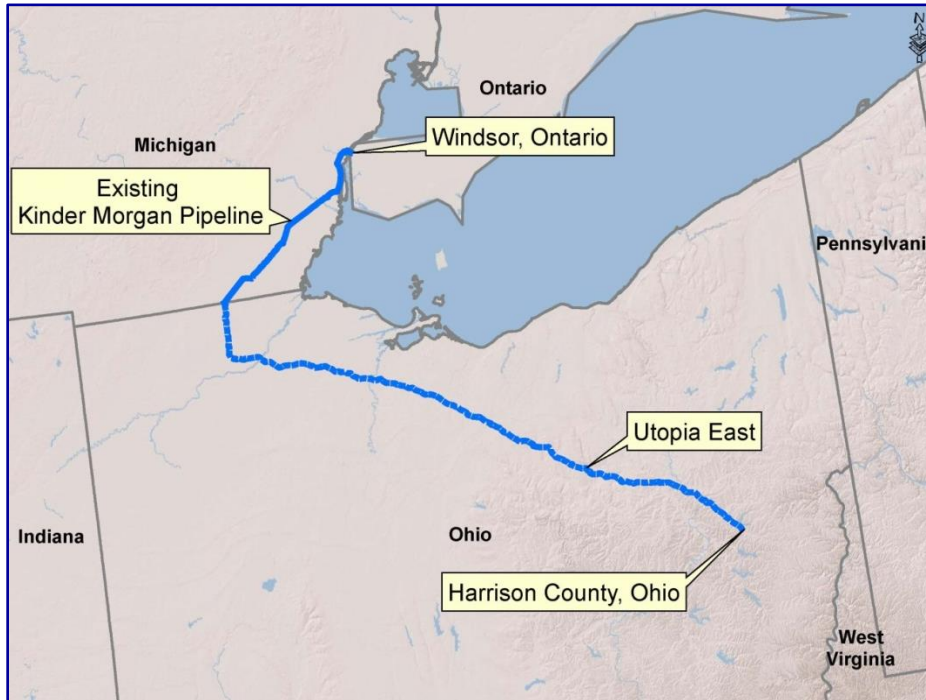
- Maintain volumes
- Focus on superior location, customer base, and connectivity



(a) Combined throughput of KMCC and Double Eagle.

(b) EIA, Drilling Report, January 2017.

Utopia Pipeline Project



■ Project Scope

- 50/50 JV with Riverstone Holdings closed on June 28, 2016
- 215 mile new build and existing 67 mile 12" pipeline
- Will transport ethane and ethane-propane mix from points in Harrison County, Ohio to Windsor, Ontario, Canada
- Supported by long-term, fee-based transportation agreement
- Initial pipeline capacity of 50 MBbl/d; expandable to 75 MBbl/d
- Approximate \$540 million^(a) investment

■ Market Drivers

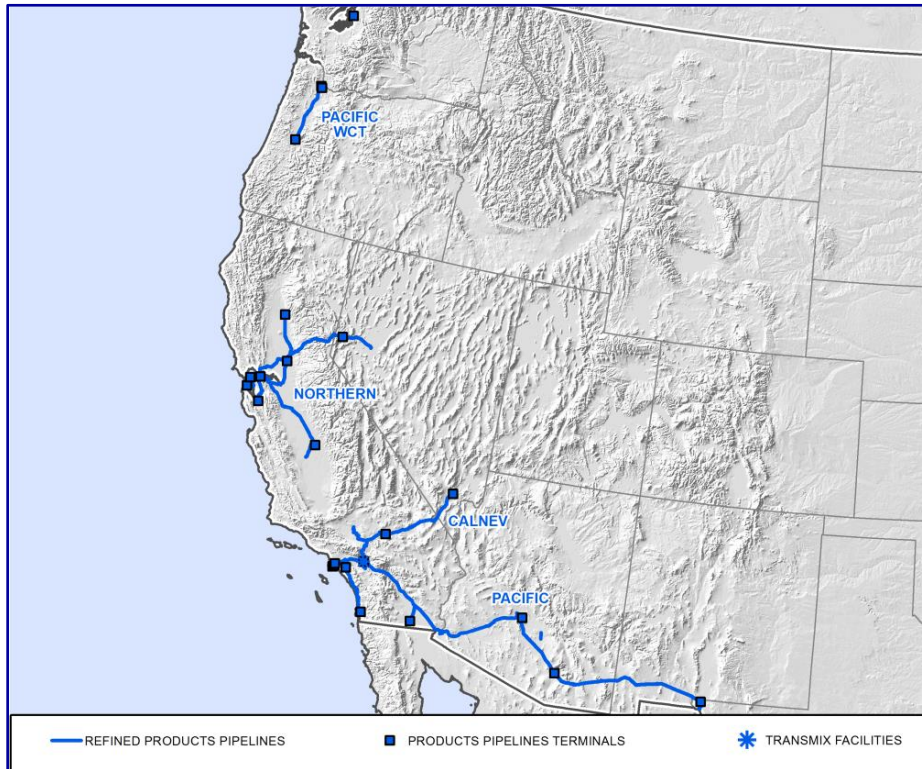
- Utopia will provide a new feedstock source for petrochemical companies in Ontario, and a new market outlet for Utica NGL producers
- Common carrier pipeline system is supported by a long-term (>20 years), fee-based transportation services agreement

■ Project Status and Timeline

- ROW acquisition ongoing
- Commencement of construction 1Q 2017
- Planned in-service date of January 2018

(a) 100% project cost, excluding AFUDC.

West Coast Region Assets



Pacific Operation: Kinder Morgan operates ~3,440 miles of refined products pipelines that serve Arizona, California, Nevada, New Mexico, Oregon, Washington and Texas

■ SFPP pipeline System:

- North Line: transports products from San Francisco Bay area refineries to delivery points in northern California and Nevada
- San Diego Line: pipeline serving major population areas in Orange County and San Diego
- Oregon Line: pipeline transports products from marine terminals in Portland to Eugene, Oregon
- West Line: pipeline transports products from the Los Angeles Basin to Arizona
- East Line: pipeline originating in El Paso, TX transports products to Arizona

■ 13 truck-loading terminals

■ CALNEV pipeline system:

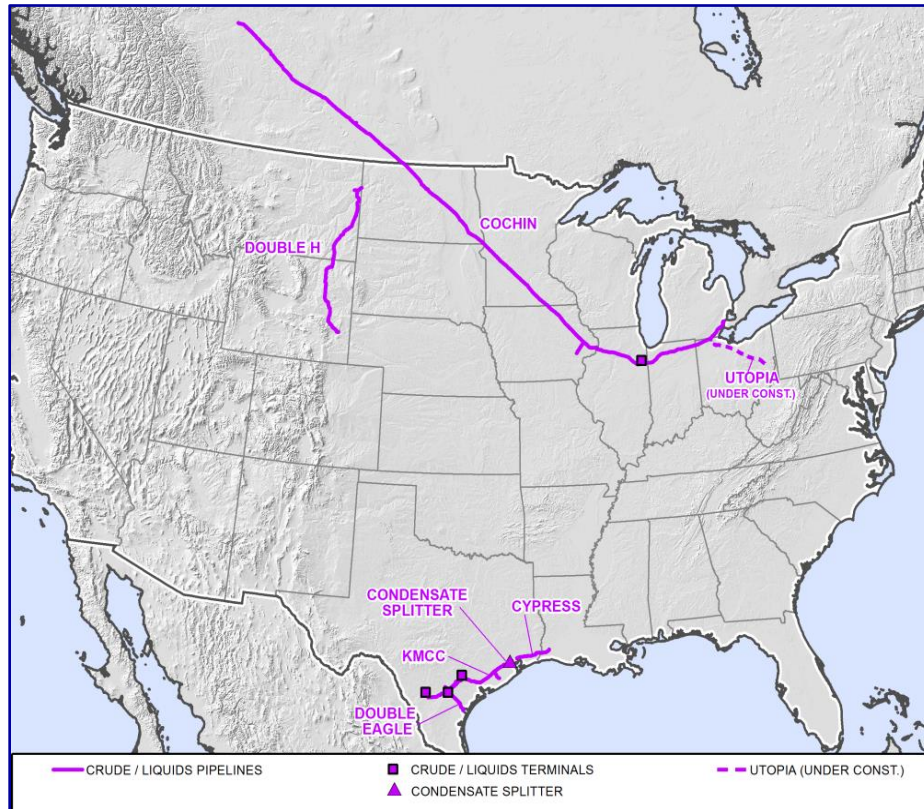
- Transports refined products from Los Angeles refineries and marine terminals to terminals in Barstow, CA, and Las Vegas, NV

■ West Coast Liquid Terminals:

- Fee-based liquid terminals along the West Coast of the U.S. with a combined total capacity of approximately 10.1 million barrels of storage for both petroleum products and chemicals

■ 2017 Plan includes 1.4 % volume increase, 0.7% margin increase vs. 2016 and 100% fee-based margin

Central Region Assets



NGL Pipelines

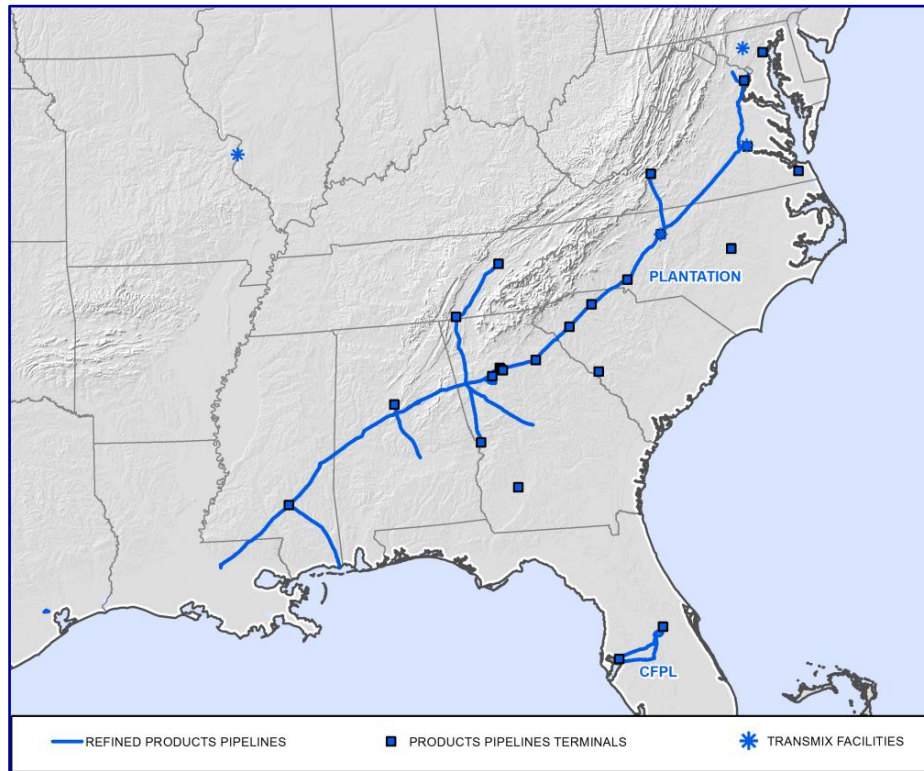
- **Cochin pipeline:** 1,810-mile multi-product pipeline between Metamora, OH and Fort Saskatchewan, Alberta currently shipping light condensate westbound from Kankakee County Illinois to Fort Saskatchewan
- **Utopia pipeline (under construction):** 215-mile new build, 12-inch diameter pipeline from Harrison County, OH to Kinder Morgan's existing pipeline and facilities in Fulton County, OH which extend an additional 67 miles to Windsor, Ontario
- **Cypress pipeline:** 100-mile natural gas liquids pipeline originating at storage facilities in Mont Belvieu, TX and extending east to Sulphur, LA

Crude & Condensate Operations

- **Kinder Morgan Crude & Condensate pipeline (KMCC):** 250-mile pipeline that originates in the Eagle Ford Shale and delivers crude/condensate to multiple terminals with access to refineries, petrochemical plants and docks on the Texas Gulf Coast
- **Double Eagle:** 190-mile pipeline that is a 50/50 joint venture between Kinder Morgan and Magellan Midstream Partners, delivers Eagle Ford shale condensate to customers in Corpus Christi, TX and KMCC
- **Double H:** 510-mile pipeline which transports crude Oil from the Bakken oil production areas near Dore, ND to terminal near Guernsey, WY with connection points including Pony Express Pipeline to Cushing, OK and the Phillips 66 refinery near Ponca City, OK
- **Condensate Splitter:** consists of two 50MBbl/d units which split condensate into its various components supported by long-term, fee-based agreement with BP North America

2017 Plan includes 100% fee-based, 99% committed margin

East Coast Region Assets



Southeast Operations:

- Plantation Pipe Line Company: 3,180-mile refined petroleum products pipeline, which originates in Louisiana and ends in the Washington, D.C. area
- Central Florida Pipeline (CFPL): 210-mile petroleum pipeline that transports gasoline, batched denatured ethanol, diesel fuel and jet fuel from Tampa to Orlando
- Southeast Terminals: 32 terminals throughout the Southeast United States located along the Plantation and Colonial Pipeline systems which handle gasoline, diesel, jet fuel and ethanol with a total storage capacity of more than 10.8 million barrels
- Kinder Morgan Transmix: facilities which process Transmix into marketable refined products in Colton CA, St Louis, MO, Greensboro, NC, Woodbine, MD and Richmond, VA

2017 Plan includes 7.9% volume increase, 5.7% margin increase and 87% fee-based margin

Terminals

Segment Presentation

Terminals

Segment Outlook

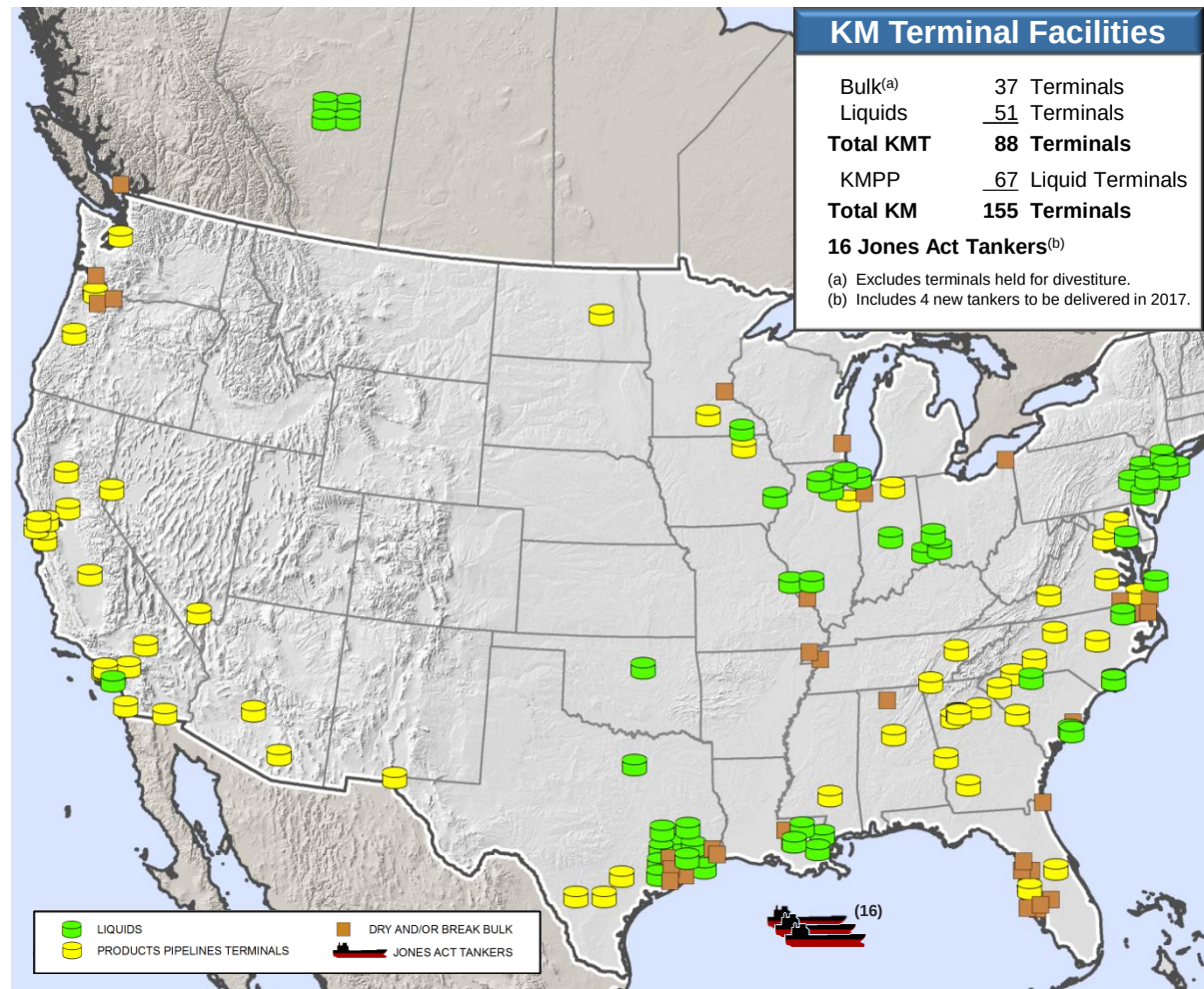
Diversified terminaling system in key refinery / market hubs

Long-term Growth Drivers

- Refined product supply and demand growth
- Gulf Coast liquids exports
- Chemical infrastructure and base business growth built on production increases
- Tuck-in acquisitions

Project Backlog

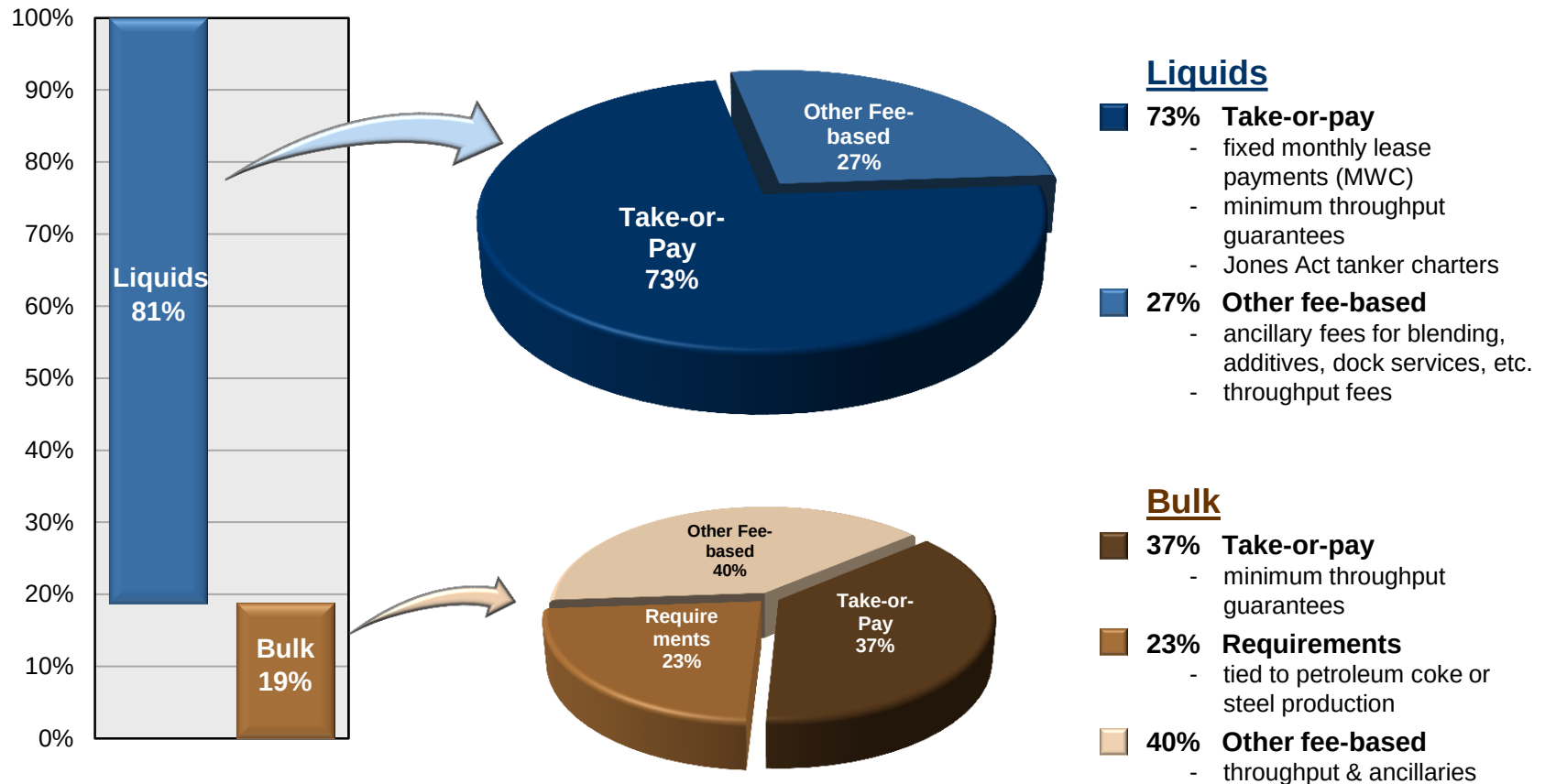
- \$1.4 billion of identified growth projects over the next two years^(a), including:
 - Houston Ship Channel network expansion
 - Edmonton merchant crude terminal
 - Jones Act tanker builds



^(a) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

Stable Fee-Based Business

- ~2/3 of KMT's 2017 budgeted EBDA is supported by take-or-pay contracts



**KMT 2017 Budgeted
EBDA = \$1,178 million**

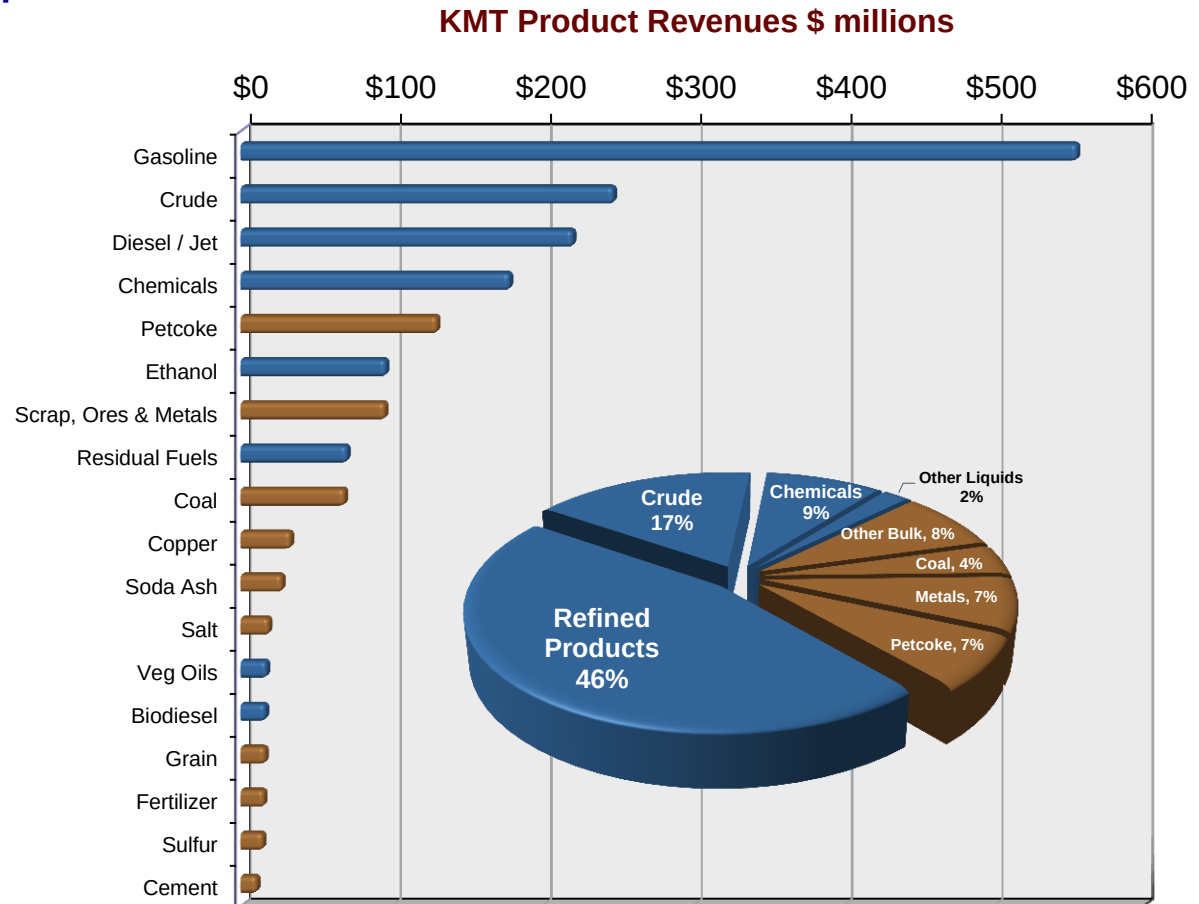
Diversified Revenues

■ Diversified revenues across liquids and bulk

	2017 Budget ^(a) (\$ millions)	(percent)
Liquids	\$1,426	74%
Bulk	\$500	26%
Total Revenue	\$1,926	100%

Top-10 Customers^(b)	\$911	47%
---------------------------------------	-------	-----

	Average remaining contract term ^(c) (years)
Liquids	3.7
Bulk	4.9



(a) 2017 budget includes non-controlling interests in certain terminals.

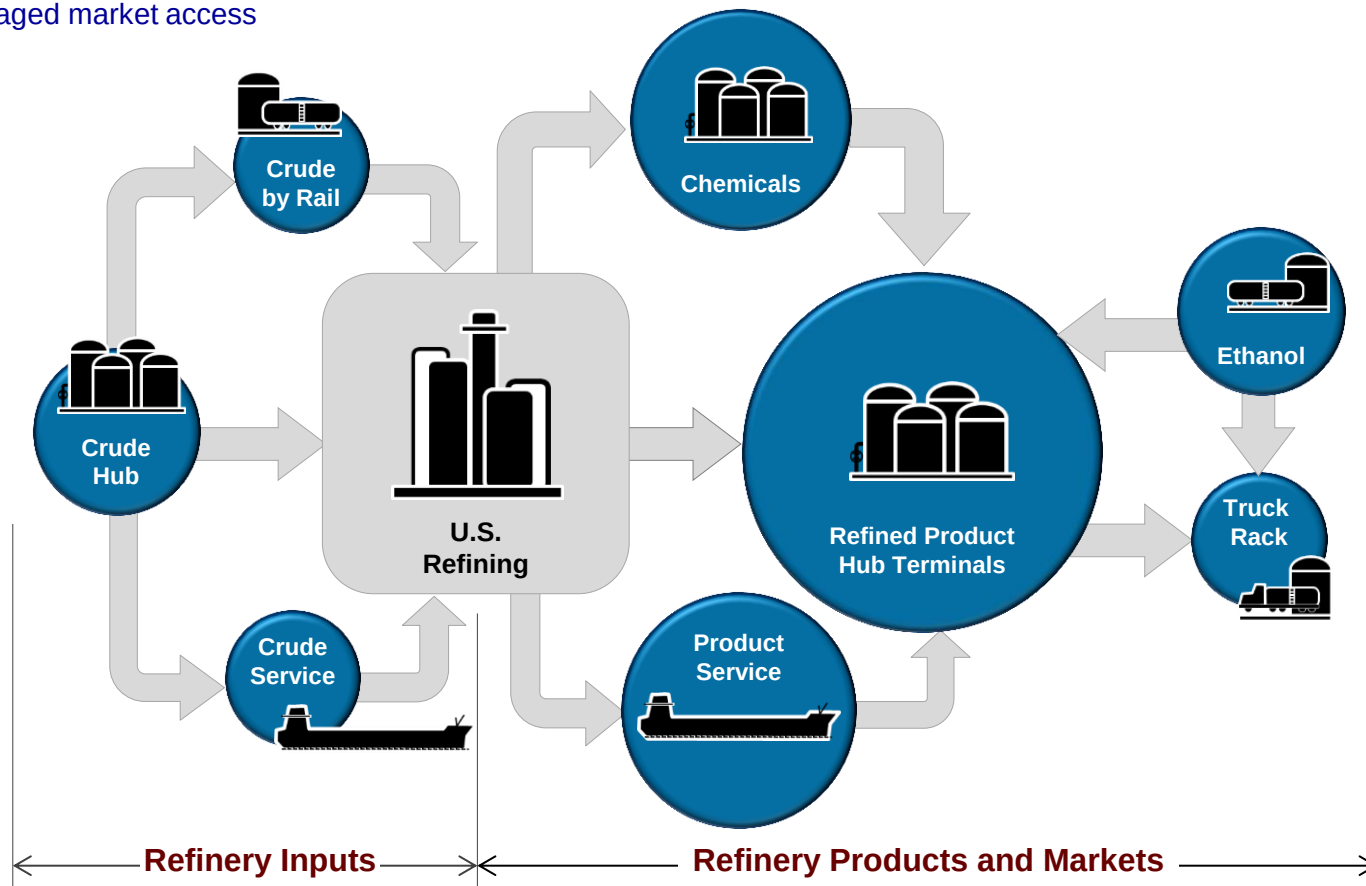
(b) No single customer is greater than 9.5% of revenues.

(c) Budget weighted average as of Jan 1, 2017.

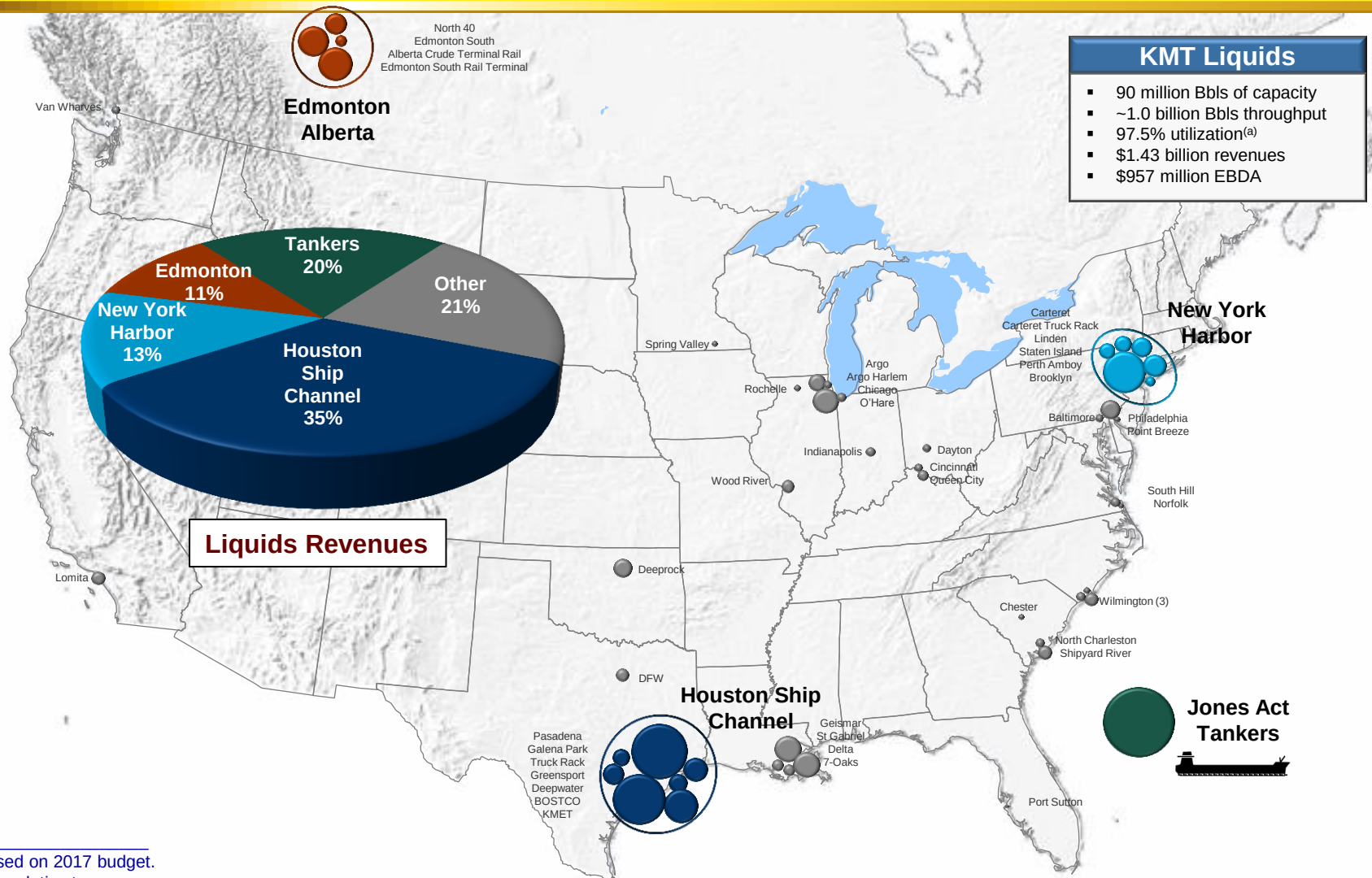
Focused on U.S. Refining

KM Terminals' logistics infrastructure serves the world's most advantaged upstream / downstream industries

- Supply of crude oil and feedstocks
- Product storage and blending
- Advantaged market access



KMT Presence in Liquids Hubs



All data is based on 2017 budget.

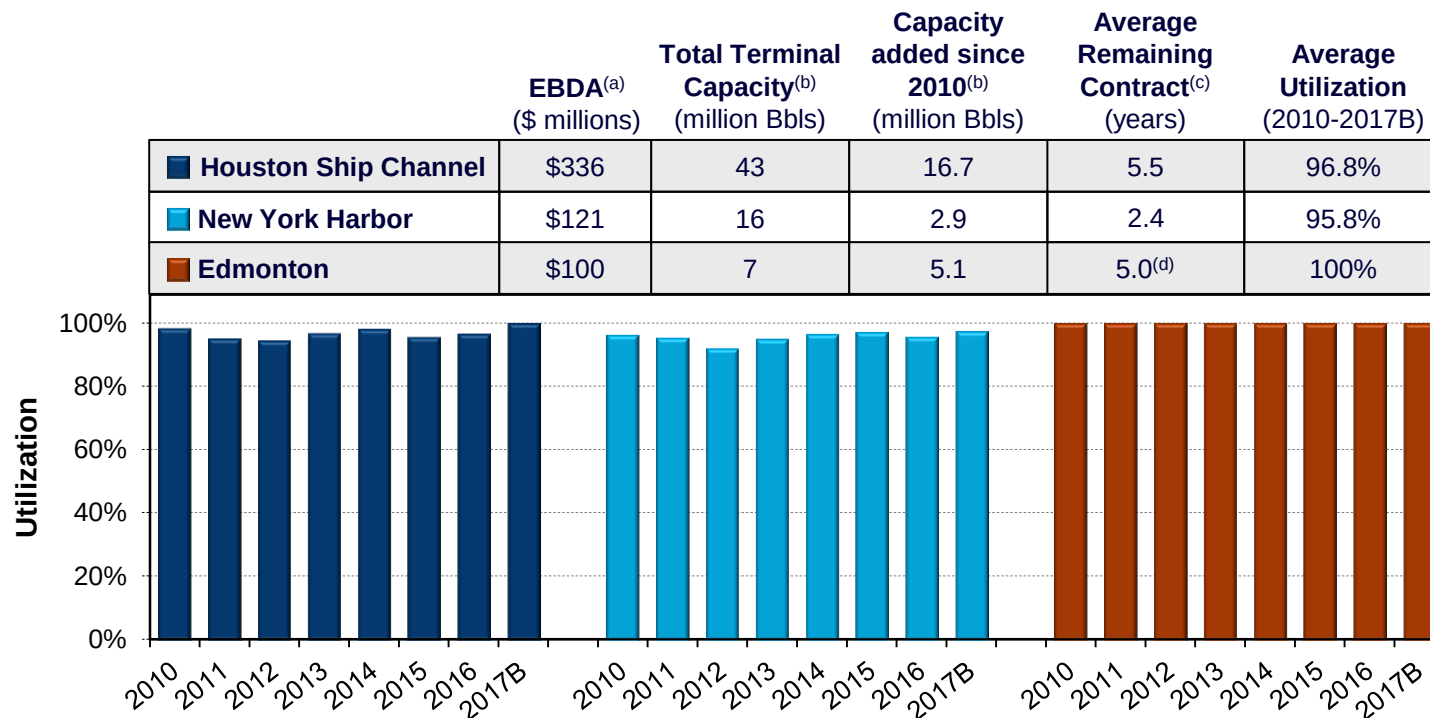
(a) Size is relative to revenues.

(b) Terminal utilizations reflect tankage unavailable for lease due to API inspections and routine maintenance.

High Demand Liquids Hubs

Critical infrastructure to industry and our customers, 100% contracted

- **Houston Ship Channel** – largest integrated refined product terminaling system in the world
- **New York Harbor** – global refined product clearing hub with liquid, transparent markets
- **Edmonton** – largest independent Canadian merchant crude terminaling system



— Terminal utilizations reflect tankage unavailable for lease due to API inspections and routine maintenance

(a) Based on 2017 budget.

(b) Includes tankage currently under construction and to be completed in 2017.

(c) As of Jan 1, 2017.

(d) Excludes Base Line Terminal which will be in service beginning in the 1st quarter 2018 – 7.5 year average contract life.

Houston – Physical Connectivity

KMT's Houston Ship Channel terminal network is the largest integrated refined product terminaling system in the world: ~43 million barrels of capacity

■ Fee-Based Business

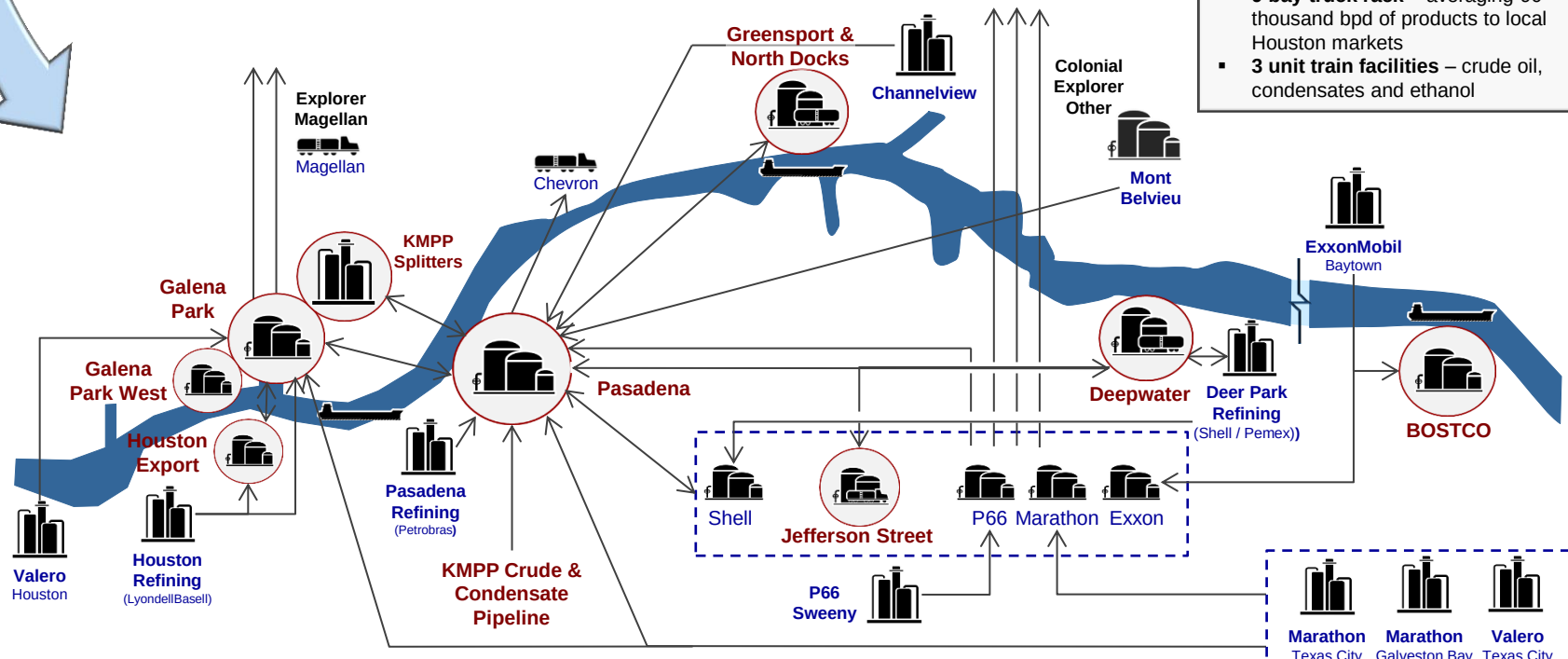
- Tank leases: term-contracted, take-or-pay commitments
- Ancillary fees: ship & barge loading & unloading, blending, transfers

■ Customer Value in in Physical Connectivity

- Multimodal: pipeline, tanker, barge, rail and truck
- Multisource: local refineries, chemical plants, Mont Belvieu, imports

Connectivity

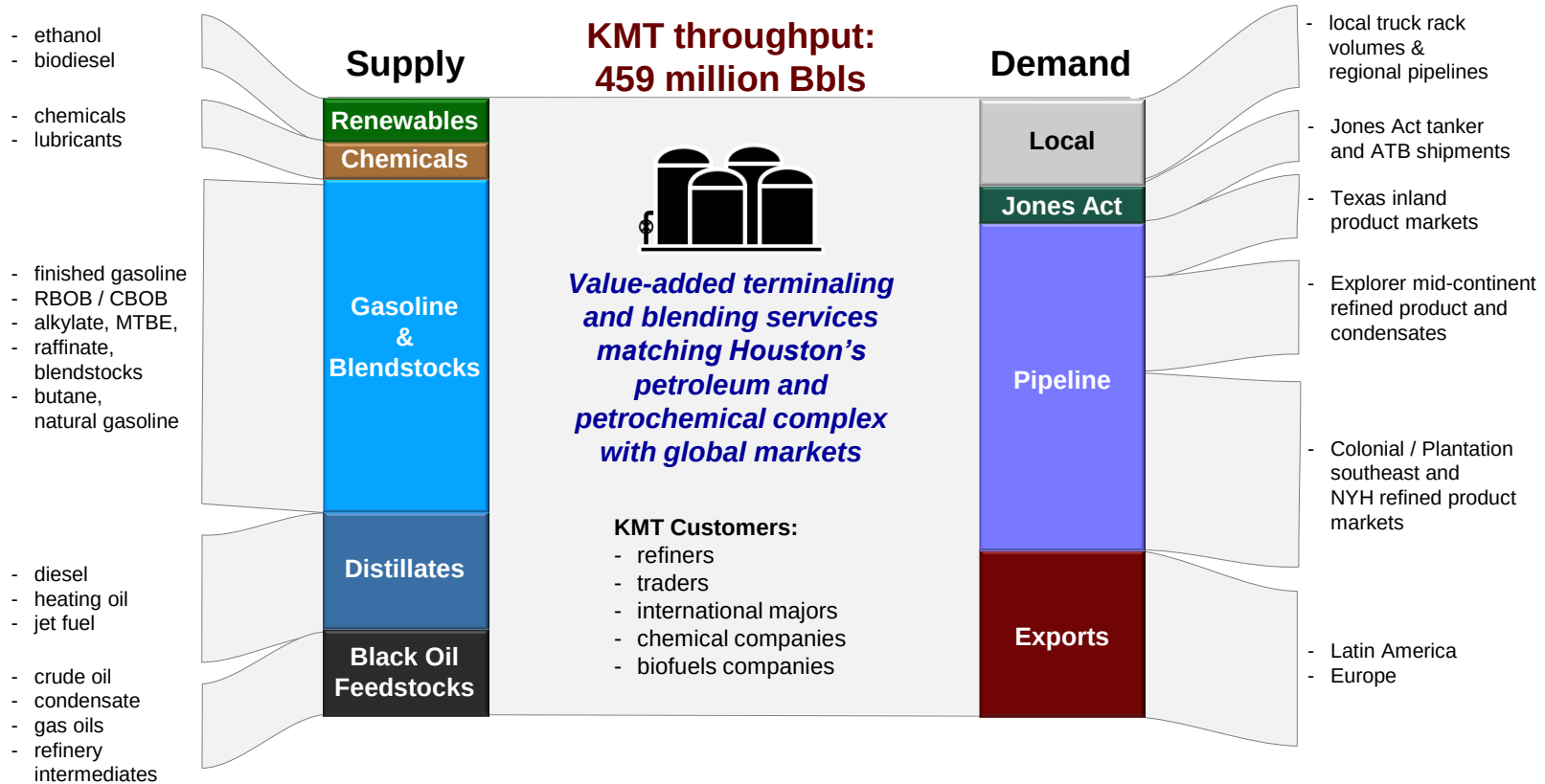
- **20 inbound pipelines** – 10 Houston area refineries and local chemical plants
- **15 outbound pipelines** – Texas, mid-continent and east coast markets
- **14 cross-channel pipelines** – interconnecting the system
- **12 barge docks** – receipt and delivery of products and blendstocks
- **11 ship docks** – serving export markets
- **9 bay truck rack** – averaging 90 thousand bpd of products to local Houston markets
- **3 unit train facilities** – crude oil, condensates and ethanol



Houston – Market Connectivity

A market-making hub serving our customers' businesses

- **Inbound:** products and blendstocks from refineries, chemical plants, renewables, and NGLs
 - staging, storage, blending services, buy/sell transfers
- **Outbound:** pipeline, truck, rail, ship and barge to domestic and international markets



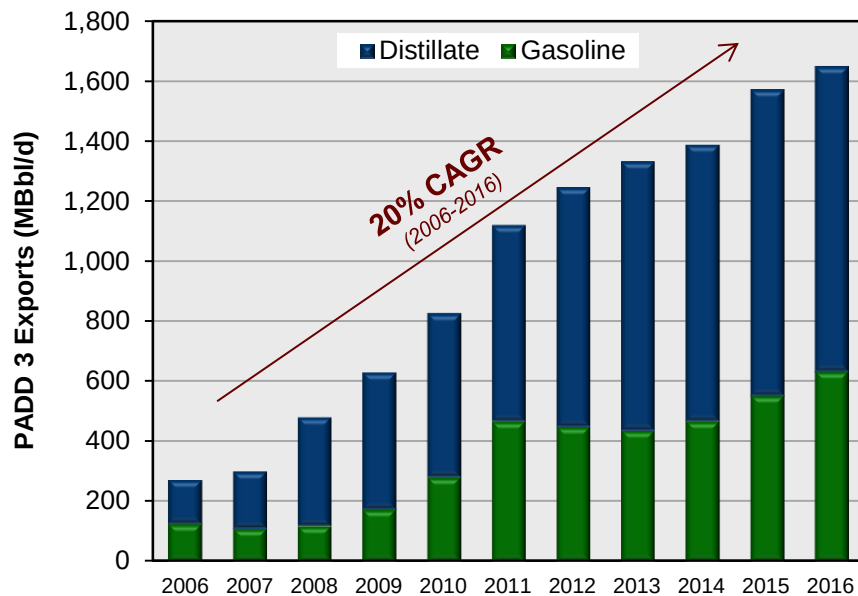
Note: Commodity and market supply and demand scaling is indicative.

- Supply representative of KMT's Houston Ship Channel business.
- Demand based on Texas Gulf Coast gasoline and distillate markets, source EIA.

Houston – Export Growth

Texas refining base becoming the world's advantaged supplier of refined products

- Houston-Galveston Port District^(a):
 - ~ 40% of PADD 3 distillate exports
 - ~ 55% of PADD 3 gasoline exports



Houston-Galveston Primary Export Markets



Houston – Expansion

Adding dock capacity with KMET, Pit 11 / North Docks projects, and other debottlenecking

- Expanding ship loading capacity to meet long-term export demand growth

Pit 11 / North Docks

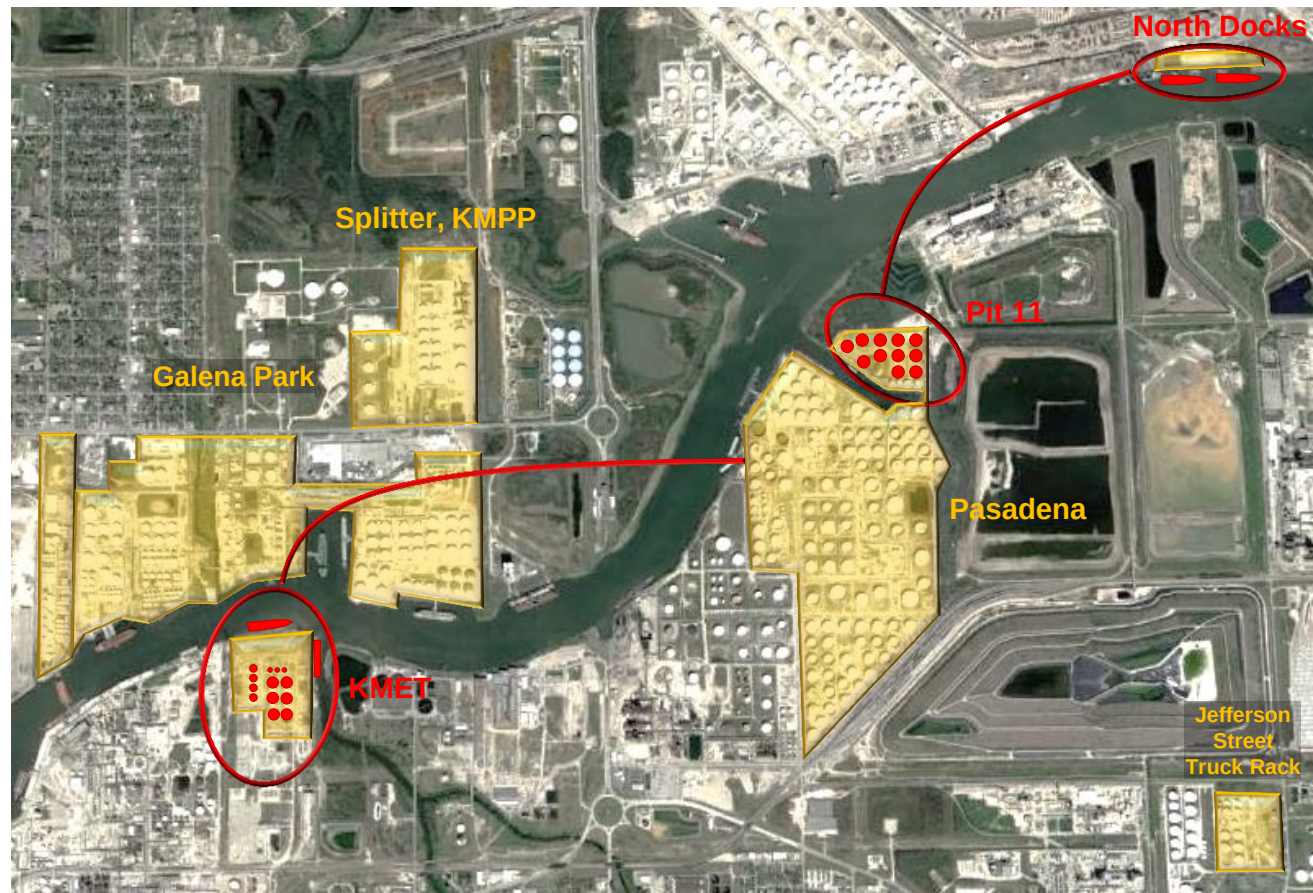
(\$258 million KM capital)

- Adds ~2.0 million Bbls of tankage
- 3 cross-channel refined product pipelines
- 2 new ship docks located at WATCO's Greensport site
- 4Q 2017 in-service

KMET

(\$245 million KM capital)

- Adds ~1.5 million Bbls of tankage
- Pipeline connectivity with Pasadena and Galena Park
- 1 new ship dock
- 1 new barge dock with 2 berths
- 1Q 2017 in-service



New York Harbor (NYH) – Physical Connectivity

A global refined product clearing hub with liquid, transparent markets: KMT with ~16 million barrels of capacity

- Fee-Based Business
 - Monthly tank leases: term-contracted, take-or-pay commitments
 - Ancillary fees: ship & barge loading & unloading, blending, transfers
- Customer Value in Physical Connectivity
 - Multimodal: pipeline, tanker, barge, rail and truck
 - Multisource: local refineries, PADD 3 pipeline receipts, imports, Jones Act vessels

Connectivity

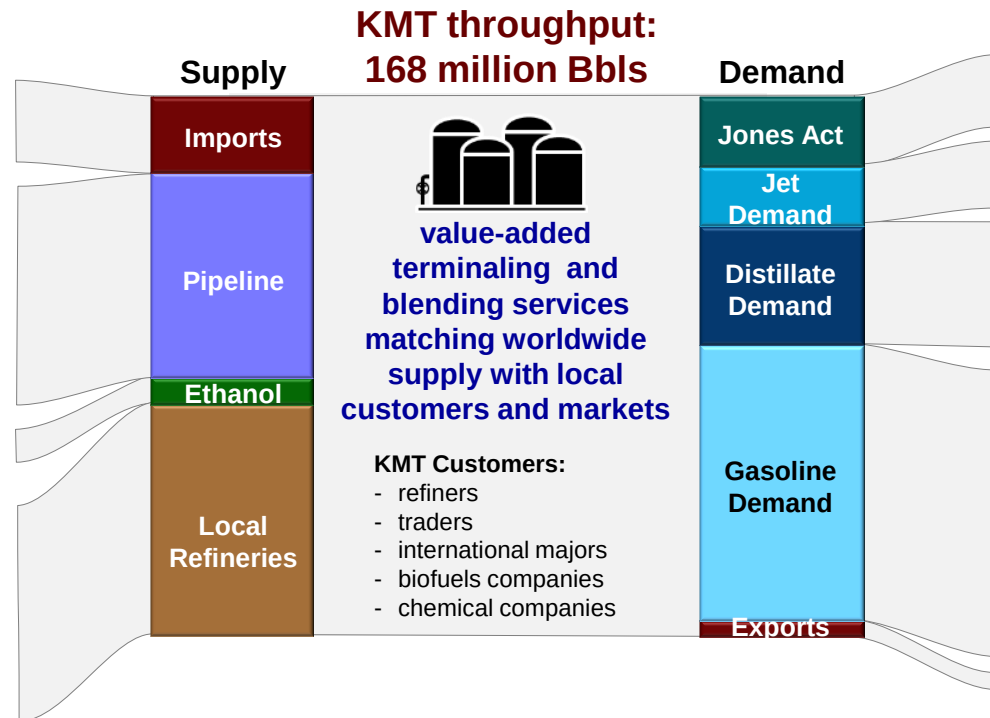
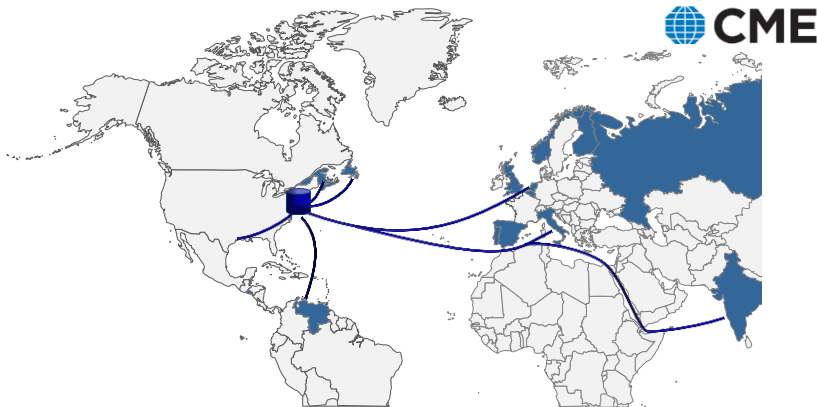
- **5 ship docks & 11 barge berths**
 - imports, exports and Jones Act movements
- **11 pipeline connections**
 - inbound and outbound connections including Colonial, Buckeye and Sunoco systems
- **2 truck racks**
 - KM:BP JV facilities in Carteret, NJ and Brooklyn, NY
- **1 unit train facility**
 - Ethanol receipts with pipeline connections to Carteret



NYH – Market Connectivity

A global refined product clearinghouse

- **Inbound:** products and blendstocks
 - Imports from Canada, Europe and worldwide
 - East Coast refineries
 - Colonial Pipeline
 - Staging, storage, blending services, buy/sell transfers
- **Outbound:** pipeline, truck rack, and barge
 - Local metropolitan markets
 - Regional pipelines
 - Inter-harbor transfers
 - Jones Act voyages to New England
 - CME delivery point for RBOB
 - Customer value in market connectivity

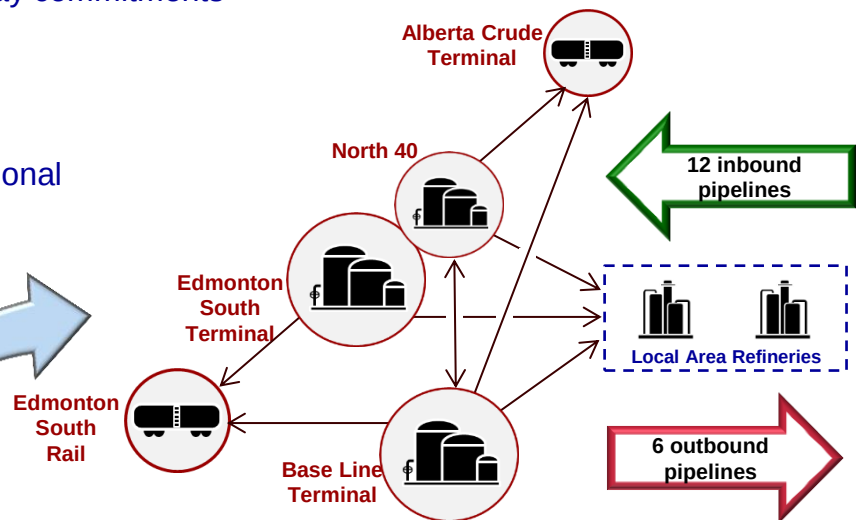
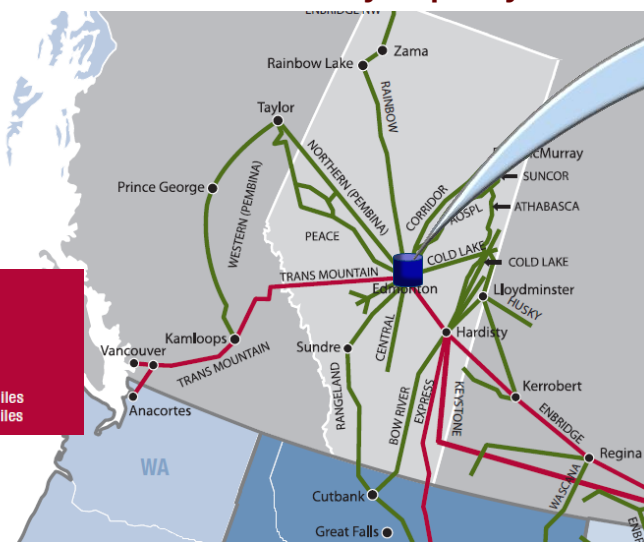


Edmonton – Physical Connectivity

KMT has the largest independent Canadian merchant crude terminaling system with ~7 million barrels of capacity^(a)

- Fee-Based Business
 - Monthly tank leases: term-contracted, take-or-pay commitments
 - Ancillary fees: blending services
- Customer Value in Physical Connectivity
 - Multimodal: pipeline and rail
 - Multisource: SAGD, mining, syncrude & conventional

Edmonton Crude Takeaway Capacity^(a)



Connectivity

- 12 inbound crude pipelines^(c)
- 6 outbound connections including Trans Mountain and Trans Mountain Expansion^(b)
- Blending and staging services
- Local refinery demand
- Crude-by-rail origination
- Key JV Partners in Imperial & Keyera

(a) Increasing to ~12 million Bbls with the addition of Base Line Terminal. Excludes KM Canada Trans Mountain Pipeline regulated tankage.

(b) Source: CAPP.

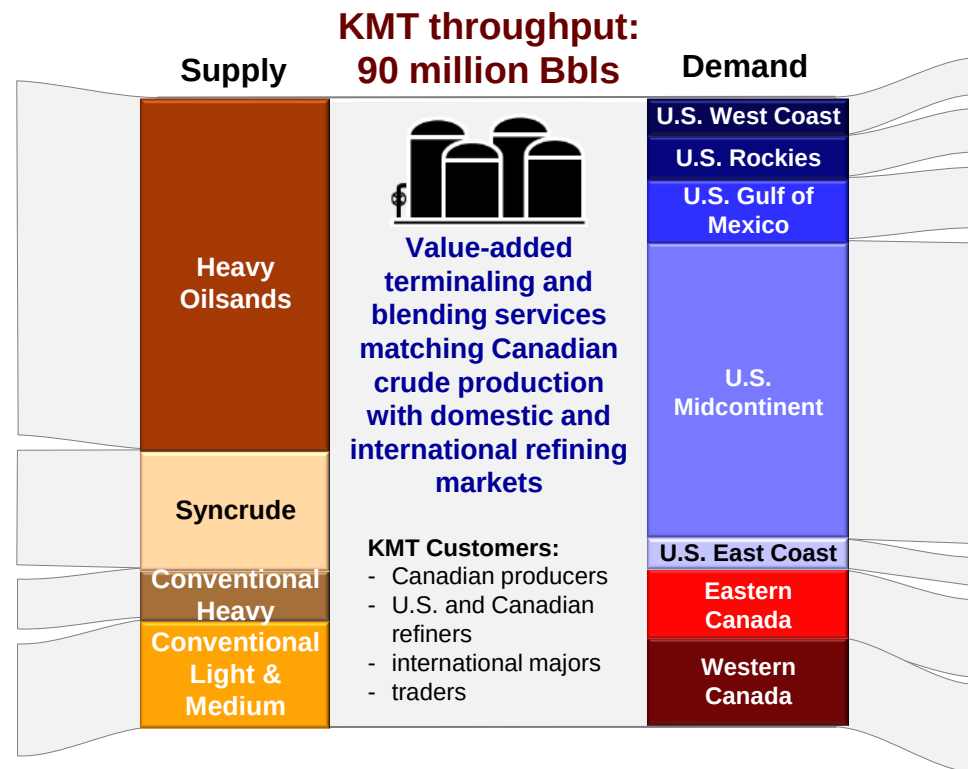
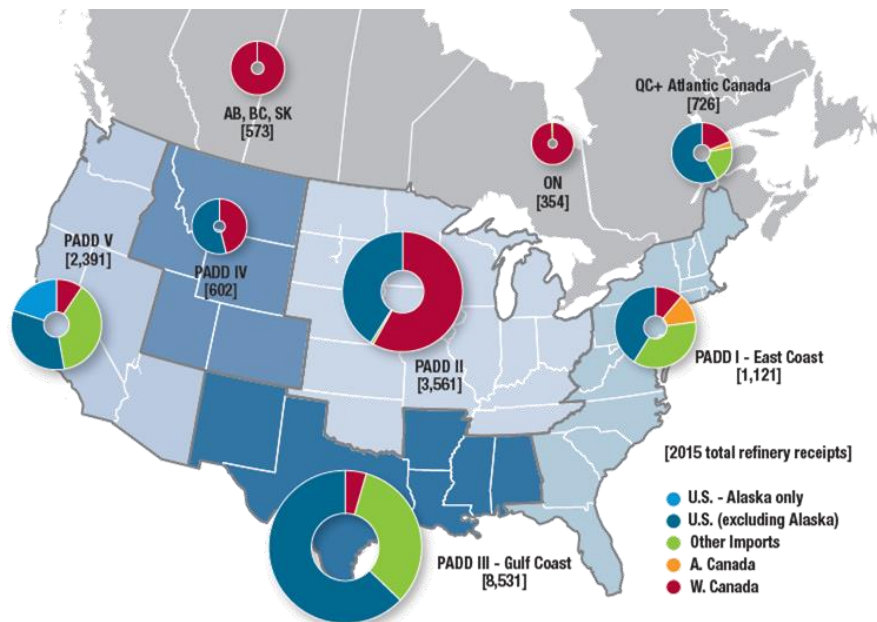
(c) Total pipeline connections vary by individual facility.

Edmonton – Market Connectivity

A Market-making Crude Hub for Western Canada

- **Inbound:** connected to a majority of Alberta production
 - Staging, storage, blending services, buy/sell transfers
- **Outbound:** pipeline and rail connections to markets
 - Trans Mountain expansion to tidewater opens foreign markets

U.S. & Canada Refinery Runs by Crude Source (MBbl/d)^(a)



Note: Commodity and market supply and demand scaling is indicative.

• Representative of Western Canada's crude production and markets, source CAPP.

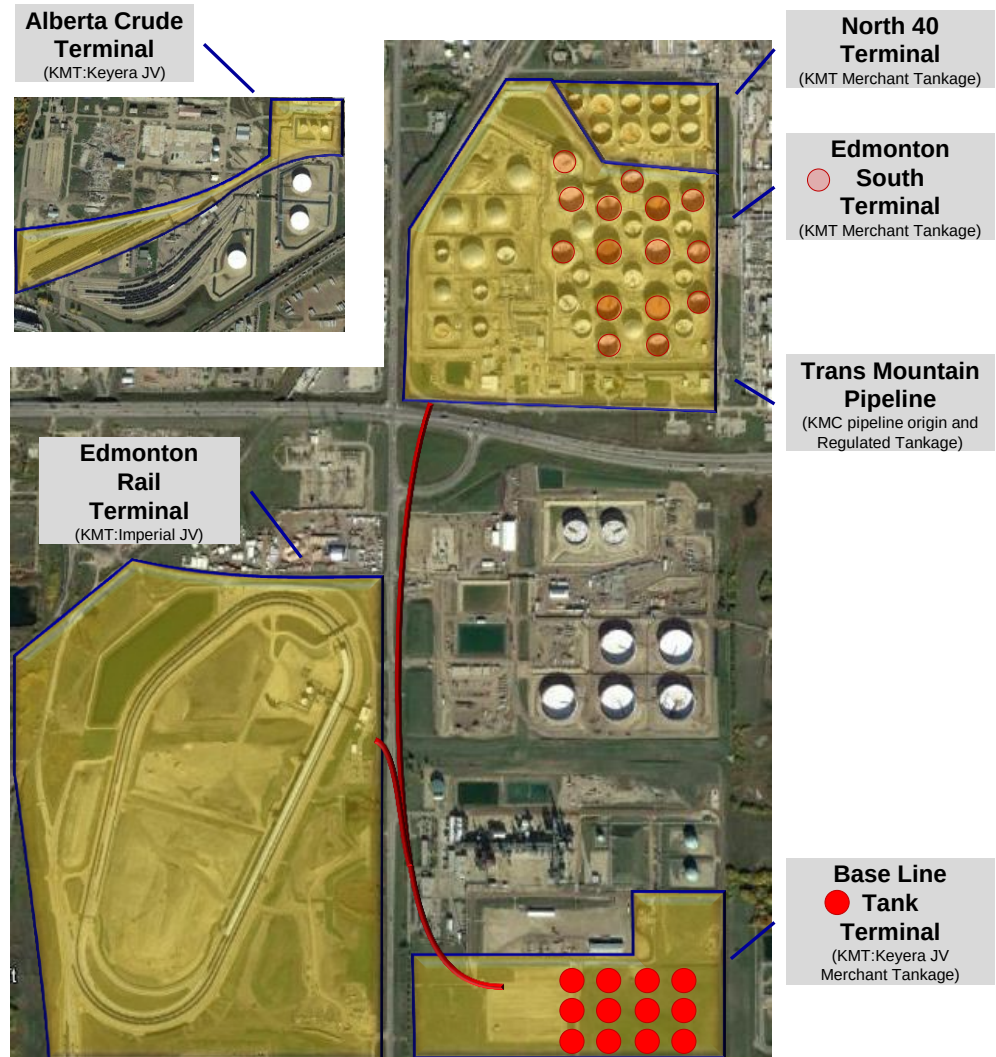
(a) Source: CAPP.

Edmonton – Expansion

Base Line Crude Terminal

(\$341 million^(a) KM capital)

- Joint Venture with Keyera
- 4.8 million Bbls crude terminal
 - 12 x 400,000 Bbl tanks
 - expansion options to 6.6 million Bbls
 - connections with KMT terminals and rail facilities, Trans Mountain and other pipelines
- 2018 phased in-service completion
 - 100% contracted
 - 7.5-year average contract length

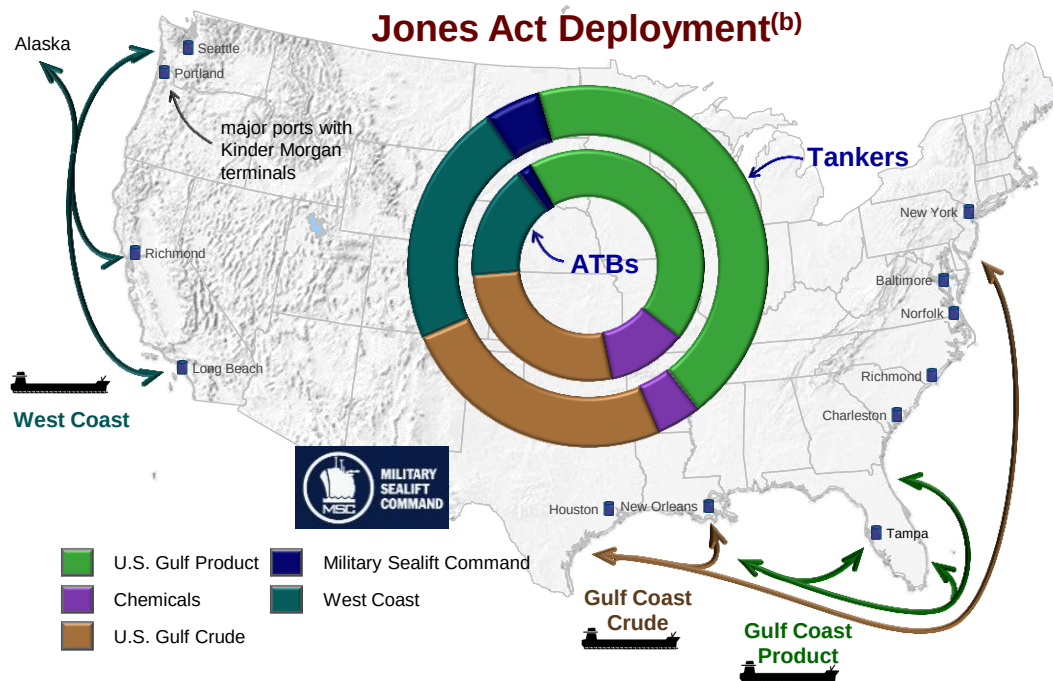


(a) Includes some capital invested by KM outside of the 50/50 JV. Certain adjustments have been made for estimated realized CAD/USD FX rates.

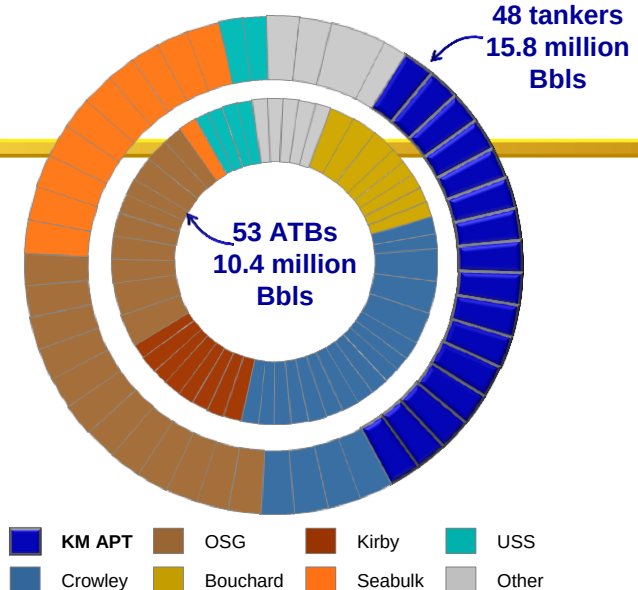
Tankers – Jones Act Markets

KM's Jones Act fleet to reach 16 tankers in 2017

- Demand has fallen alongside Eagle Ford production declines
 - Vessels have shifted to U.S. Gulf and West Coast product trade
 - New vessel deliveries adding to near-term market length
 - Short-term expected shift of ATB charters toward Tankers
 - Long-term development of extended Jones Act markets



U.S. Jones Act Fleet^(a)



American Endurance

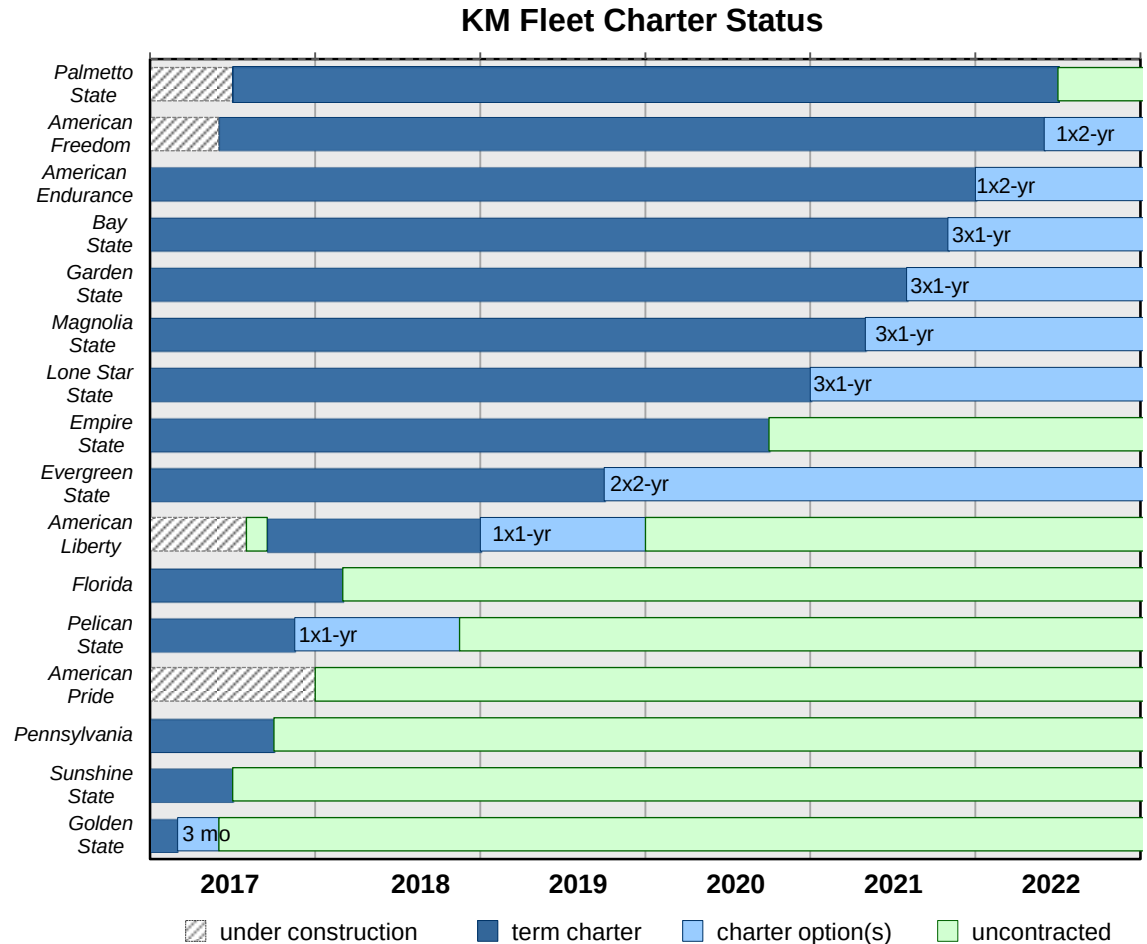
(a) Includes vessels currently under construction, excludes tankers currently in ANS crude service, and does not reflect any retirements / rationalization.

(b) Service relative to capacity. Source data: Navigistics Consulting's Wilson Gillette Report, December 2016 .©

Tankers – APT Jones Act Fleet

All of APT's available vessels are sailing under time-charter with limited 2017 exposure

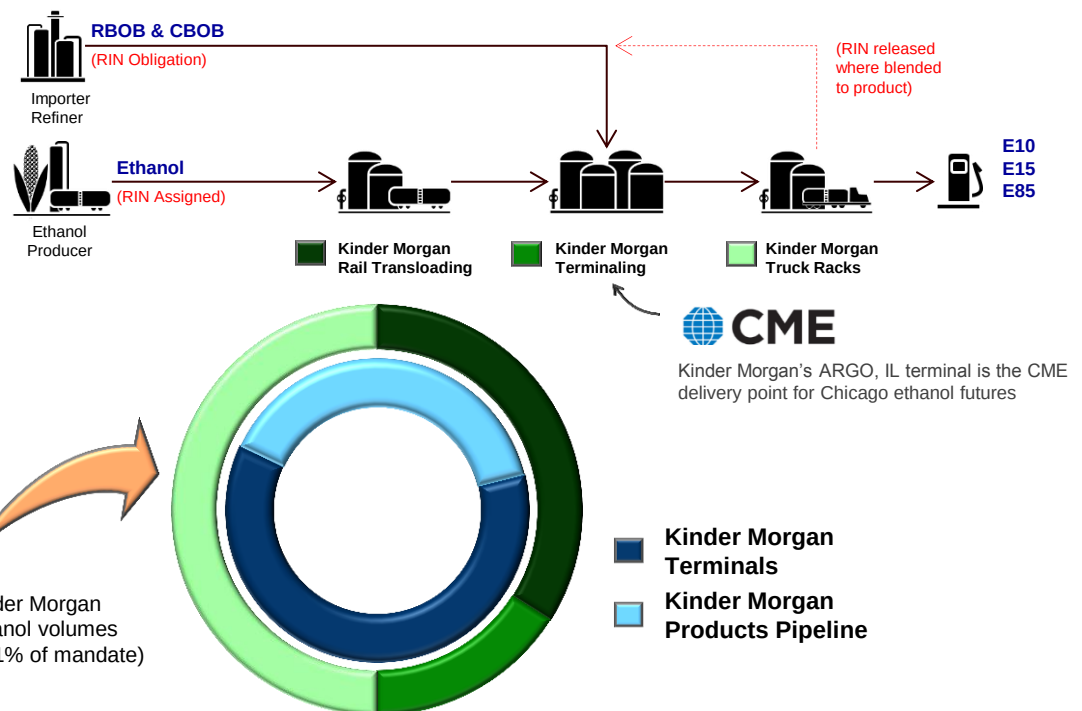
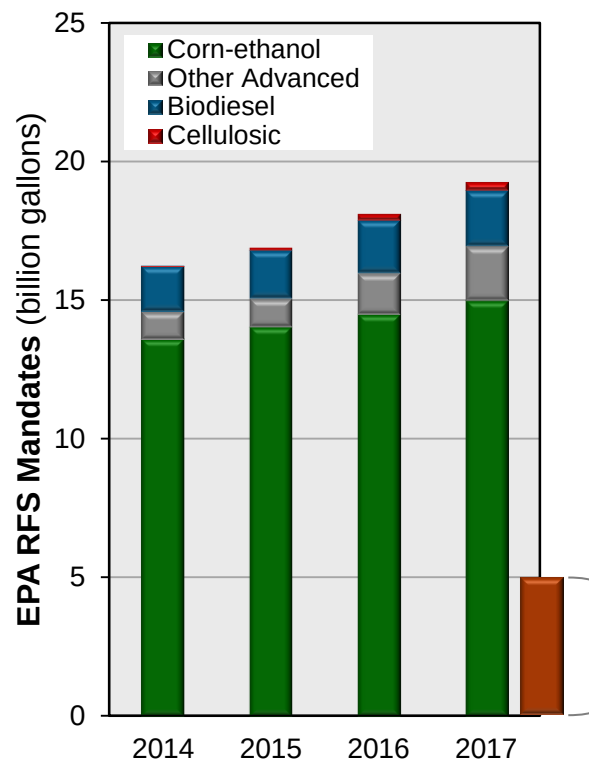
- Average term contract length of 2.8 years across 16-vessels
- 4 new vessels to be delivered in '17
 - American Freedom
 - Palmetto State
 - American Liberty
 - American Pride
- Currently-uncontracted vessels:
 - **\$2.9 million or 0.2% exposure to KMT's 2017 budgeted EBDA**
- Marketing
 - Short-term charters
 - Bundled terminaling services
 - Prompt market voyages



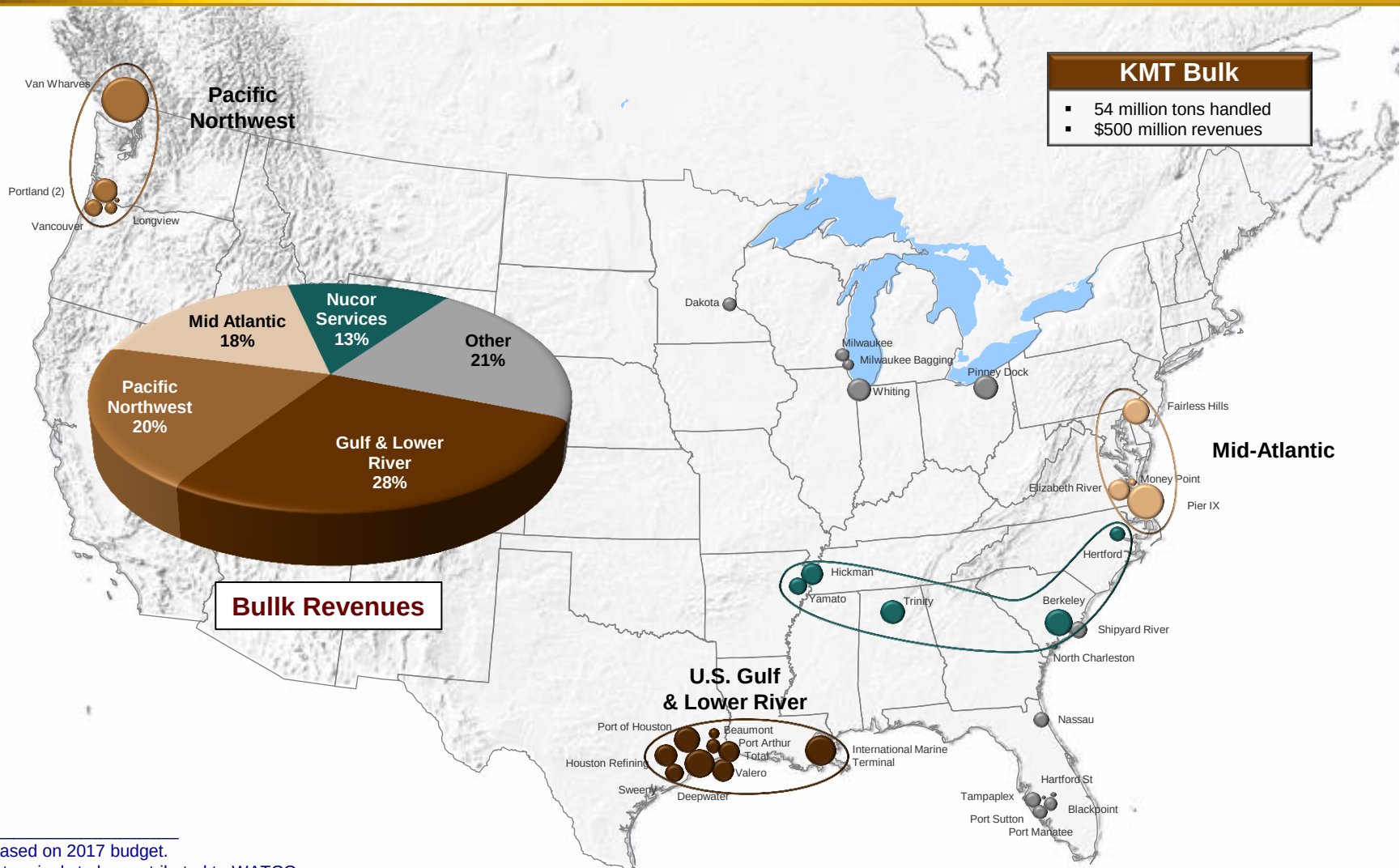
Renewables – Value Chain

KMT's diversified, multimodal ethanol service offerings capture ~31% of U.S. demand

- Increasing midstream solutions needed to meet RFS
 - Ethanol mandates require higher level ethanol blends (E15 and E85 market penetration)
 - Advanced biofuel mandates require increasing imports of biodiesel, qualifying feedstocks, and Brazilian ethanol

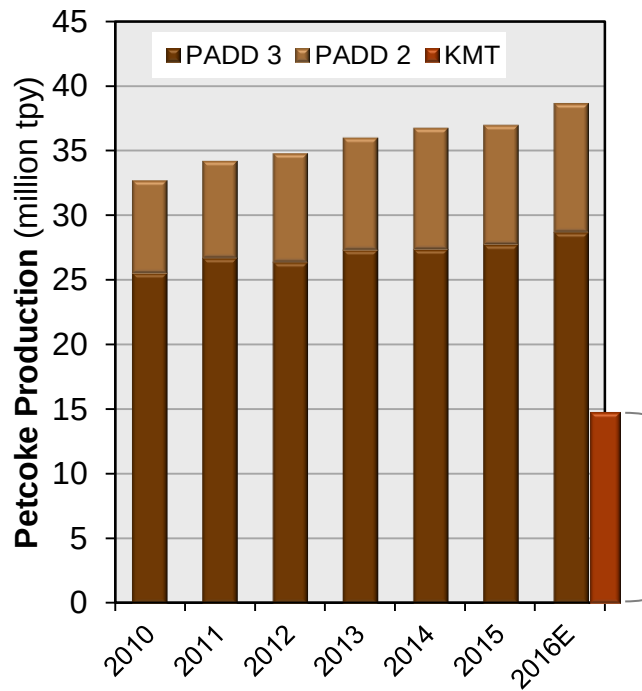


Bulk Industry Hubs



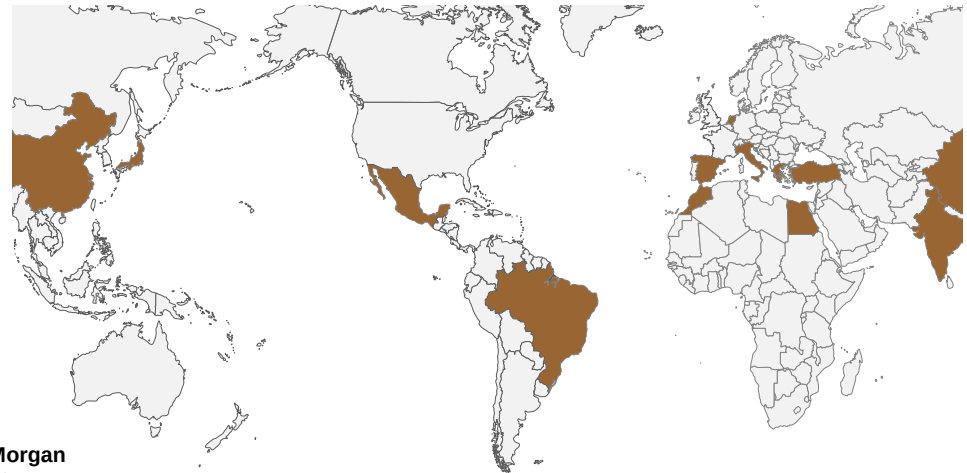
Petroleum Coke – Value Chain

KMT is the largest U.S. petcoke handler

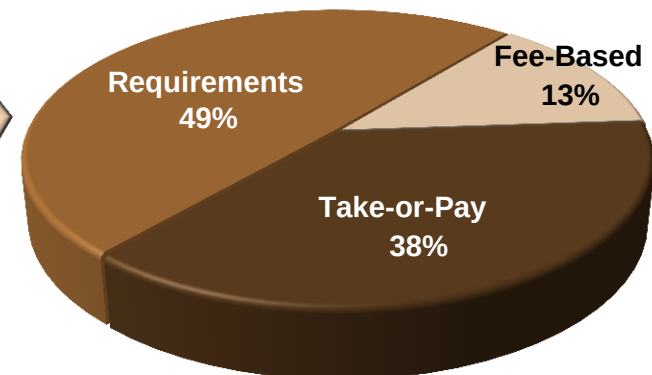


Kinder Morgan
petcoke tonnage
(~38% of production)

Top U.S. Petcoke Export Markets



KMT Petcoke Revenues



Refinery Services, BP Whiting



Deepwater Export Terminal, Houston Ship Channel

Vancouver Wharves

A diversified Canadian multi-commodity export hub

- Strategically located in the Port of Vancouver for trans-Pacific trade growth
- 6 million tons of export capacity
- 4 separate berths handling multiple commodities
 - Copper exports and zinc concentrate imports
 - Diesel exports and biodiesel imports
 - 3.0 million tons sulfur export capacity
 - 1.5 million tons wheat and canola export capacity
- \$190 million in KMT investment since acquisition
 - connecting key Canadian industries to global markets
 - import / export expansion available



Canadian Highland Valley Copper Mine^(a)



Canadian Canola Field^(b)



CN Canadian Sulfur Unit Train^(c)

(a) Source: Teck.
 (b) Source: Canola Council of Canada.
 (c) Sultran.

Terminals Segment Historical Growth

	2013 Actual	2014 Actual	2015 Actual	2016 Actual ^(a)	2017 Budget ^(b)
Revenue (net)	\$1,388,319	\$1,689,930	\$1,843,578	\$1,878,836	\$1,926,469
Opex	576,822	681,381	760,094	710,138	708,976
Adjusted EBITDA	\$811,497	\$1,008,549	\$1,083,484	\$1,168,698	\$1,217,493
Book Income Tax	13,621	29,707	28,713	35,827	39,359
EBDA before Certain Items	\$797,875	\$978,854	\$1,054,771	\$1,132,871	\$1,178,134
Sustaining Capital	104,654	140,721	141,940	141,691	167,596
DCF	\$693,221	\$838,133	\$912,831	\$991,180	\$1,010,538
Expansion Capital	\$817,137	\$728,273	\$570,899	\$699,333	\$688,049
Operating Margin	58.45%	59.68%	58.77%	62.20%	63.20%
Growth from prior year (earnings before DD&A)	6.06%	22.68%	7.76%	7.40%	4.00%
Internal	5.52%	16.20%	3.23%	4.98%	3.72%
Acquisition	0.53%	6.48%	4.53%	2.42%	0.28%
					EBDA CAGR
					12.22% ^(c)

(a) Includes terminals contributed to WATCO through closing.

(b) Excludes JV sustaining capital.

(c) 15-year cumulative average growth (2002-2017).

Terminals Projects Placed in Service during 2016

Project Name	Product	Capacity	Capital (MM) ^(a)	First Full Year EBITDA	In Service	Avg. Contract Length ^(b)
North Docks 1 & 2 (Greens Port)	Refined Products	200K bpd	\$72.4		Q1/16 - Q4/16	7.5
South Hill Tankage (Wilmington, NC)	Methanol	0.1MM Bbls	\$6.6		Q1/16	7
Galena Park Infrastructure Improvements	Gasoline Blendstock	n/a	\$40.0		Q2/16	7
Jones Act Tankers (4) ^(c)	Crude/Products	1.3MM Bbls	\$621.2			
<i>Magnolia State</i>					Q2/16	5
<i>Garden State</i>					Q3/16	5
<i>Bay State</i>					Q3/16	5
<i>American Endurance</i>					Q4/16	5
Carteret Product Tanks	Gasoline	0.3MM Bbls	\$32.1		Q3/16	5
Rubicon GLT Expansion	MDI/Aniline	0.1MM Bbls	\$14.4		Q3/16	14
TOTAL			\$786.8	\$86.4		6

(a) Net to KM, includes capitalized overhead.

(b) Initial term.

(c) Capital for State Class tankers include a portion of allocated purchase price.

Terminals Project Backlog

Project Name	Product	Capacity	Capital (MM) ^{(a) (b)}	First Full Year EBITDA ^(b)	Expected In Service	Avg. Contract Length ^(c)
Houston Export Terminal	Blendstock	1.5MM Bbls	\$244.7		Q1/17	11
Jones Act Tankers (4)	Crude/Products	1.3MM Bbls	\$604.6			
<i>Palmetto State</i>					Q2/17	5
<i>American Endurance</i>					Q2/17	5
<i>American Freedom</i>					Q3/17	1
<i>American Liberty</i>					Q4/17	n/a
Pit 9 Pasadena Tank Project	Refined Products	0.3MM Bbls	\$25.7		Q2/17	7
Galena Park Ship Dock 3 Expansion	Lube Oil	25K bpd	\$7.3		Q3/17	15
Jefferson Street Truck Rack VRU	Gasoline	37K bpd	\$5.7		Q3/17	n/a
Pit 11 Development	Refined Products	2.0MM Bbls	\$185.1		Q4/17	7
Edmonton Base Line Terminal ^(d)	Crude	4.8MM Bbls	\$341.4		Q4/18	7.5
TOTAL			\$1,414.4	\$138.9		7

(a) Net to KM, includes capitalized overhead.

(b) Certain adjustments have been made for estimated realized CAD:USD FX rates.

(c) Initial term.

(d) Includes some capital invested by KM outside of the 50/50 JV.

Terminals Liquids Throughput

		Variance to Budget			
		Actual 2016 ^(a)	Budget 2017 ^(a)	Amt	%
KMLT Throughput (bbls)	Chemical	44,147,450	47,495,296	3,347,847	7.0%
	Distillate	139,270,328	158,940,986	19,670,658	12.4%
	Gasoline	422,735,919	480,222,777	57,486,858	12.0%
	Fuel Grade Ethanol / Bio-diesel	66,697,344	68,895,473	2,198,129	3.2%
	Petroleum ^(b)	219,870,740	222,672,613	2,801,872	1.3%
	Other	3,497,996	4,440,026	942,030	21.2%
	Vegetable Oils	5,148,847	5,277,896	129,049	2.4%
	Animal Fats	3,426	-	(3,426)	0.0%
	Oil Fields	222,540	371,100	148,560	40.0%
Totals		901,594,591	988,316,168	86,721,577	8.8%
KMLT Utilization	Capacity Utilization Rate ^(c)	94.8%	97.5%		
	Capacity (MM bbls)	87.8	90.5		

Key Take-aways:

- Gasoline and distillate volume growth led by liquids hub expansions and export volume growth
- Chemicals growth reflects continued industry growth and terminaling demand
- Biofuels volumes commensurate with RFS mandates
- Petroleum crude throughput growth at Edmonton reflecting marginal increases to Alberta production

(a) Excludes terminals divested or held for divestiture.

(b) Primarily crude oil and black oils.

(c) Terminal utilizations reflect tankage unavailable for lease due to API inspections and routine maintenance.

Terminals Bulk Tonnage

		Variance to Budget			
		Actual 2016 ^(a)	Budget 2017 ^(a)	Amt	%
KMBT Tonnage (tons)	Coal	7,857,117	6,823,538	(1,033,579)	-15.1%
	Petcoke	13,523,672	14,155,518	631,846	4.5%
	Cement (Including Clinker)	966,392	972,383	5,991	0.6%
	Fertilizers	2,382,631	2,470,764	88,132	3.6%
	Salt	2,051,992	2,412,738	360,745	15.0%
	Ores/Metals (Bulk & Break-Bulk)	14,855,106	15,290,381	435,275	2.8%
	Soda Ash	4,694,914	4,461,777	(233,137)	-5.2%
	Aggregate	3,594,798	3,948,466	353,669	9.0%
	Other Bulk	2,735,955	2,813,106	77,151	2.7%
	Totals	52,662,576	53,348,670	686,095	1.3%

Key Take-aways:

- Declining coal volumes as a result of depressed export markets
- Increased petcoke tonnage reflects increased export handling at Pier IX and IMT and high refinery utilizations
- Base business budgeted growth of 1.3%

CO_2

Segment Presentation

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CO₂

Segment Outlook^(a)

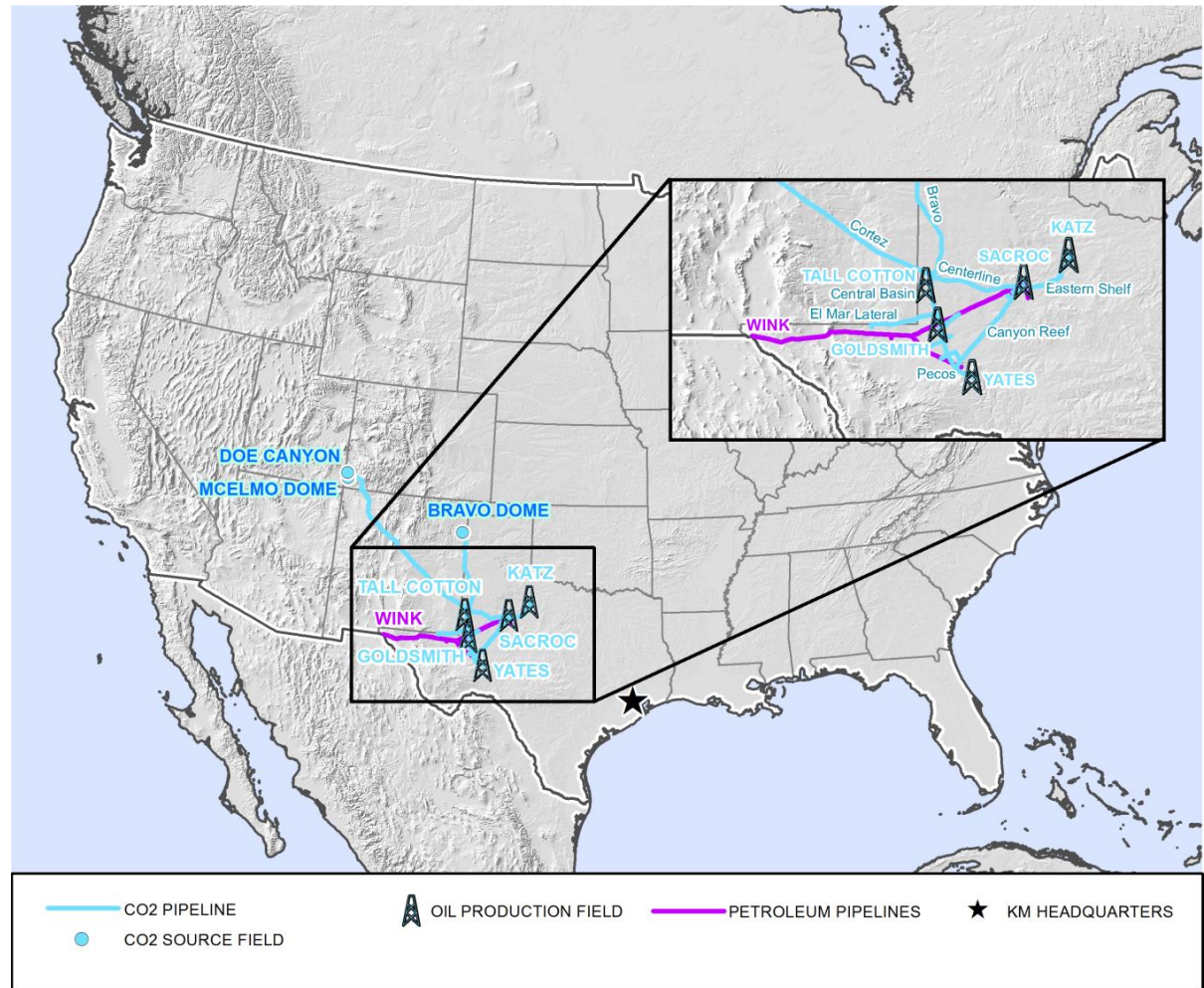
Own and operate best source of CO₂ for EOR

Long-term Growth Drivers:

- Demand for scarce supply of CO₂ drives volume and price
- Expect to maintain current CO₂ production levels with minimal incremental investment
- Billions of barrels of domestic oil still in place to be recovered in the Permian Basin
- >9 billion barrels Original Oil In Place in KM operated fields

Project Backlog:

- Identified growth projects totaling \$0.3 billion and \$1.1 billion in S&T and EOR, respectively, over next five years^(b), including:
 - S&T: Southwest Colorado CO₂ production
 - EOR: SACROC / Yates / Goldsmith / Tall Cotton oil production



(a) EOR = Enhanced Oil Recovery, S&T = Source & Transportation.

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

2017 Projects – Price Sensitivity

AT IRR % vs Oil Price

\$/Bbl	\$50 flat	\$53 flat	\$60 flat	Forward Curve ^(a)
SACROC-Bypass (Long Lateral)	27%	32%	44%	37%
SACROC-Bypass (Sidetrack Lateral)	41%	47%	61%	50%
SACROC Hawaii	14%	19%	30%	22%
Yates Horizontal Drain Hole Program	65%	73%	96%	75%
Tall Cotton Phase 2	32%	36%	43%	38%

■ **Budgeted 2017 operating cash costs:**

- SACROC = \$17.91 /Bbl
- Yates = \$13.14 /Bbl

(a) Forward curve as of 1/18/2017.

KM CO₂ Current Outlook

\$4.7 Billion Cumulative Free Cash Flow Generated Since Inception^(a)

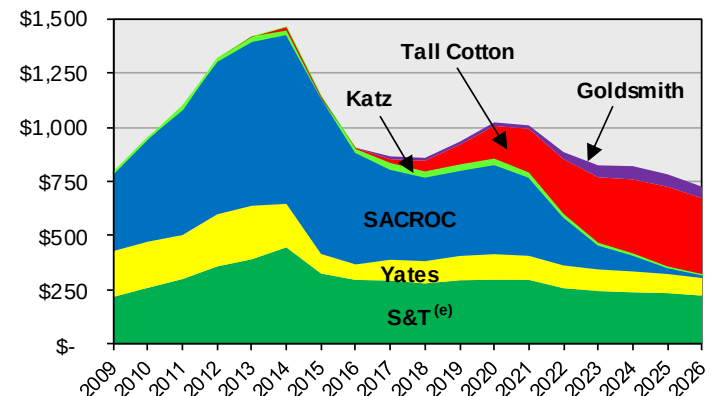
Development Plans 2017-2026

- **SACROC**
 - Continue platform development/redevelopment
 - Expand Bypass Pay/Infill programs
 - Exploit transition zone opportunity
- **Yates**
 - Continue HDH programs and gravity drainage depletion plan
 - Initiate new Westside Waterflood
 - Evaluate HCM pilot
- **Katz**
 - Continue conformance program
 - Optimize flood performance
- **GLSAU**
 - Continue downspacing evaluation
 - Optimize flood performance
- **Tall Cotton**
 - Commence Phase 2 expansion
 - Develop additional project prospects
- **CO₂ S&T**
 - Maintain capacity in existing source fields (McElmo & Doe Canyon)
 - Optimize production and increase efficiency
 - Manage source portfolio to be prepared for increase in demand

■ Total Business IRR (2000-2026): 28.2%

2017-2026	Net BOE ^(b) (MMBOE)	KM Share Capex (\$MM) ^(c)
SACROC	58	\$697
Yates	26	143
Katz	7	61
GLSAU	12	268
Tall Cotton	46	1,006
CO ₂ S&T		442
Total	150	\$2,617

DCF (\$MM)^(e)



(a) Net of invested capital.

(b) Net BOE = Net Crude plus Net NGLs plus Net Residue Gas sold and thereafter divided by 6.

(c) KM Share Capex is inclusive of Capitalized CO₂ and Capitalized OH.

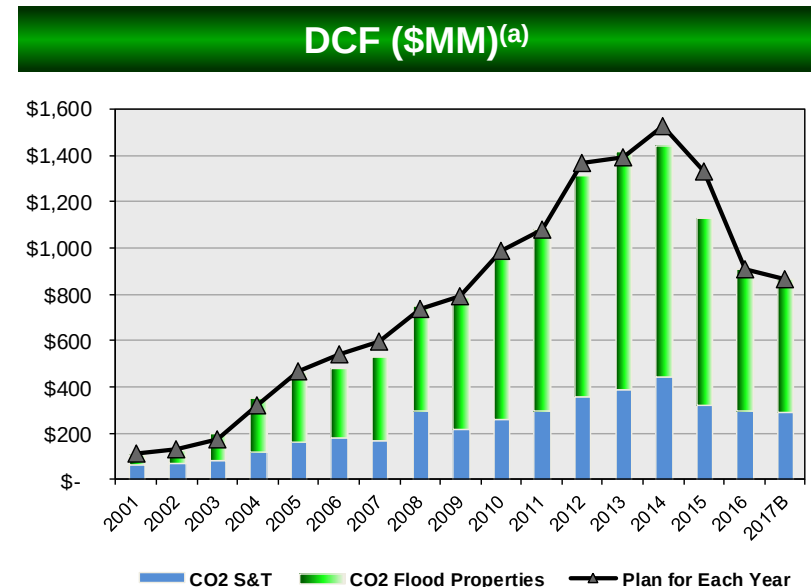
(d) 2017 = Budget, 2017 at \$53/Bbl, 2018 at \$55/Bbl, 2019 at \$60/Bbl, 2020+ at \$65/Bbl; cost metrics based on 2016 run rate; development plans may change in different price scenarios.

(e) CO₂ profits not eliminated from S&T.

History of CO₂ Group and Looking Forward

Track Record – Consistently very close to budget despite inherent volatility

- Shell CO₂ formed in 1998, KM share 20%
- Acquired remaining 80% in April 2000
- Acquired SACROC interests June 2000
- Acquired Yates interests in 2001 and 2003
 - Feb 24, 2016 - 1.5 billionth barrel of oil produced
- Ramped up developments at SACROC 2003+
 - Constructed Centerline pipeline in 2003
 - Constructed power plant in 2005
 - Increased oil production 3X+
- Acquired Wink pipeline in 2004
- Acquired Katz field 2006
- Increased SW Colorado CO₂ capacity 30% 2008
- Katz CO₂ project: CO₂ injection commenced Dec-2010
- 2013-Acquired Goldsmith Landreth San Andres (GLSAU)
- Tall Cotton (ROZ) CO₂ project: CO₂ injection commenced Nov-2014
- Increased SW Colorado CO₂ capacity 13% in 2015
 - 200 MMcf/d
- Increased Cortez Capacity to 1.5Bcf/d in 2016
- Initiated Tall Cotton Phase II in 2016

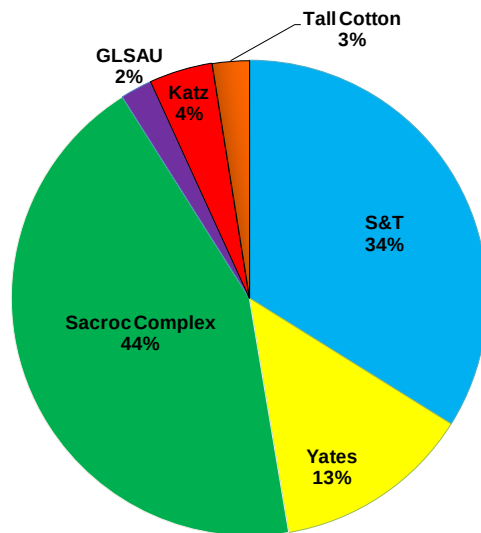


Our assets, resources and technologies provide us with growth opportunities

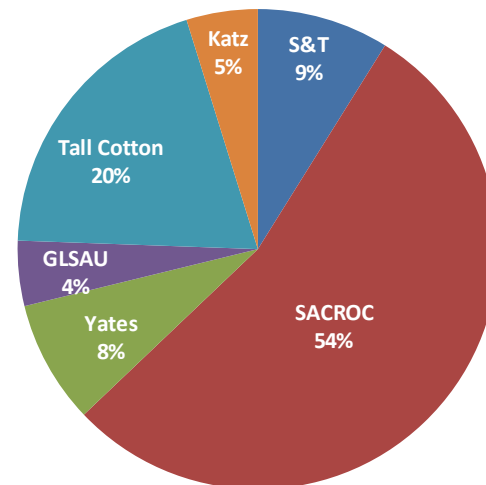
- Stable CO₂ demand
- Continued developments at SACROC, Yates, Tall Cotton/ROZ, and GLSAU

2017 DCF and Capex by Asset Group^(a)

2017 DCF = \$866 MM



2017 Budget – \$352 MM Expansion Capital

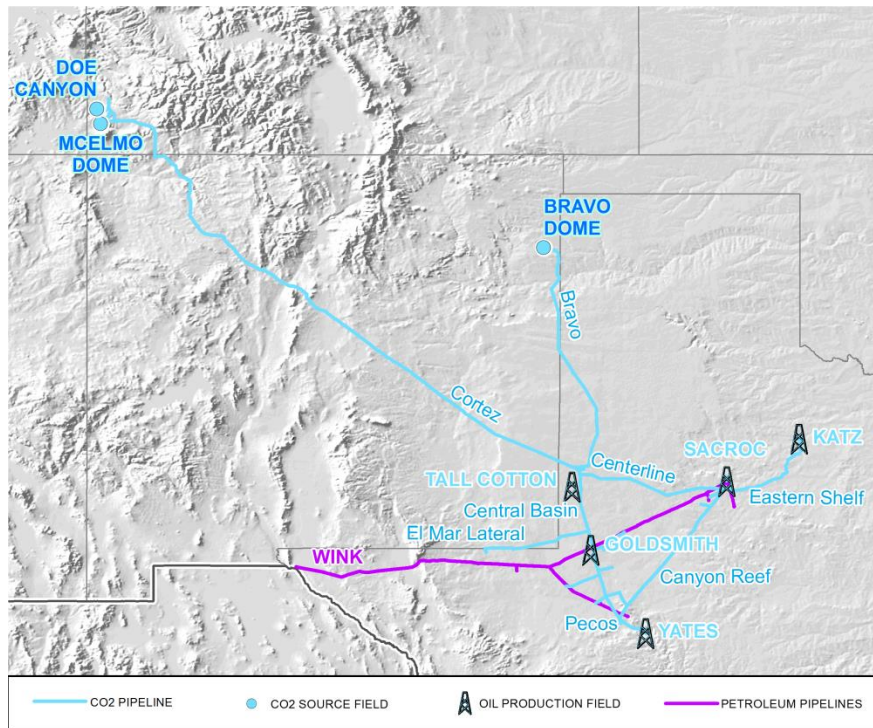


Impact of Oil Price / Volume Variance on 2017 DCF

(\$ in millions)

2017 Budget:	\$866MM
<u>Volume +/- 1,000 Bbl/d</u>	
SACROC / Katz / GLSAU / Tall Cotton	\$15.0MM
Yates	\$8.1MM
 <u>CO₂ Volume +/- 50 MMcf/d</u>	 \$7.2MM
 <u>Oil Price +/- \$1/Bbl WTI</u>	
NGL	\$1.6MM
CO ₂	\$0.3MM
Crude	<u>\$2.5MM</u>
TOTAL:	\$4.4MM
 <u>NGL/Crude Ratio +/- 1%</u>	 \$2.3MM
 <u>Mid/Cush Diff +/- \$1/Bbl</u>	 \$8.3MM

CO₂ Asset Summary



Original gas in place (TCF)

McElmo Dome	22
Doe Canyon	3
Bravo Dome	12

CO ₂ Reserves	KMI Interest	Location	Remaining Deliverability	Operator
McElmo Dome	45%	SW Colorado	20+ years	KMI
Doe Canyon	87%	SW Colorado	10+ years	KMI
Bravo Dome	11%	NE New Mexico	10+ years	Oxy

Pipelines	KMI Interest	Location	Capacity (MMcf/d)	Operator
Cortez	50%	McElmo Dome to Denver City	1,500	KMI
Bravo	13%	Bravo Dome to Denver City	375	Oxy
Central Basin (CB)	100%	Denver City to McCamey	700	KMI
Canyon Reef	98%	McCamey to Snyder	290	KMI
Centerline	100%	Denver City to Snyder	300	KMI
Pecos	95%	McCamey to Iraan	125	KMI
Eastern Shelf	100%	Snyder to Katz	110	KMI
Wink (crude)	100%	McCamey & Snyder to El Paso	145 MBbl/d	KMI

Crude Reserves (a)	KMI Interest / (Net of royalty)	Location	Operator
SACROC	97% (83%)	W Texas	KMI
Yates	50% (44%)	W Texas	KMI
Katz	99% (83%)	W Texas	KMI
Goldsmith	100% (88%)	W Texas	KMI
Tall Cotton	100% (88%)	W Texas	KMI

Note: In addition to KMI's interests above, KMI has a 22%, 51%, and 100% working interest in the Synder gasoline plant, Diamond M gas plant and North Synder plant, respectively.

(a) Reserve life ~4 years based on current independent consultant reserve report.

2017 Expansion Program Summary

Capex Program \$352MM^(a)

S&T – \$31MM Capex (incl. \$4MM Cap OH)	\$31MM	9%
■ Continue Cow Canyon development ■ CO₂ Production 1,310 MMcf/d		
SACROC – \$190MM Capex^(b,c) (incl. \$52MM Cap OH & Cap CO₂)	\$190MM	54%
■ Activate 20 conventional patterns in Hawaii project area ■ Expand success Bypassed Pay Program – 23 pattern equivalents in 2017 ■ Execute Phase 1 redevelopment of Bullseye Project Area ■ Purchase 70 MMcf/d CO₂, Produce 27.5 MBbl/d oil, 20.9 MBbl/d NGL		
Yates – \$29MM Capex^(c) (incl. \$9MM Cap OH & Cap CO₂)	\$30MM	8%
■ Drill 40 HDH wells ■ Purchase 81 MMscf/d CO₂ ■ Produce 18.1 MBbl/d oil		
Katz – \$17MM Capex (incl. \$16MM Cap OH & Cap CO₂)	\$17MM	5%
■ Continue conformance activity and optimize flood performance ■ Purchase 40MMcf/d CO₂, Produce 4.2 MBbl/d oil		
GLSAU - \$15MM Capex (incl. \$10MM Cap OH & Cap CO₂)	\$15MM	4%
■ Continue lift conversions ■ Complete replacement injectors and seismic acquisition ■ Purchase 33MMcf/d CO₂, Produce 2.3 MBbl/d oil		
Tall Cotton - \$69MM Capex (incl. \$18MM Cap OH & Cap CO₂)	\$69MM	20%
■ Activate 15 patterns with Phase 2 expansion ■ Purchase 39 MMcf/d CO₂, Produce 2.2 MBbl/d oil		
Total Capex^(a)	\$352MM	100%

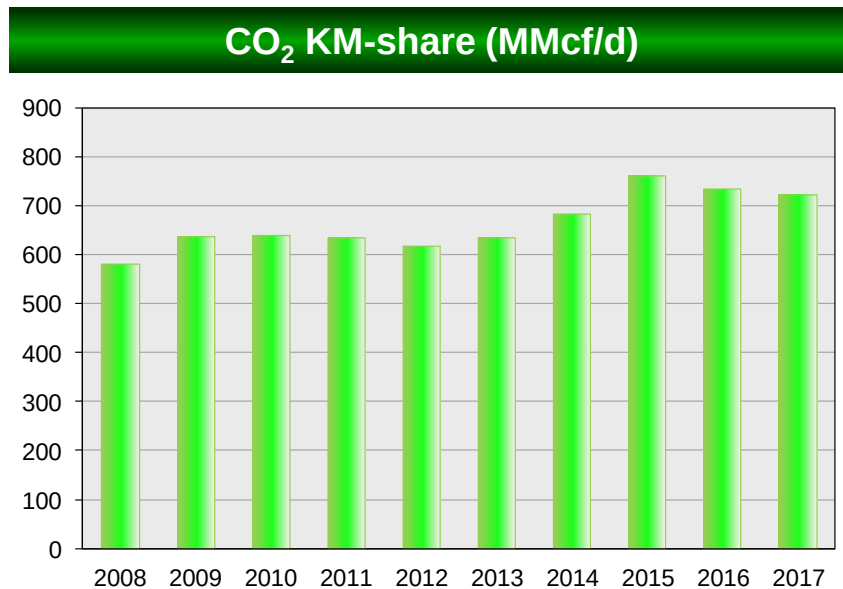
(a) Included in \$352 million total capex program are overhead and CO₂ purchases, in the aggregate, of approximately \$109 million.

(b) Includes minor properties, unallocated costs.

(c) Includes secondary objectives.

CO₂ Entitlement Volumes

Produced and Sold to our Customers



Significant growth since 2008:

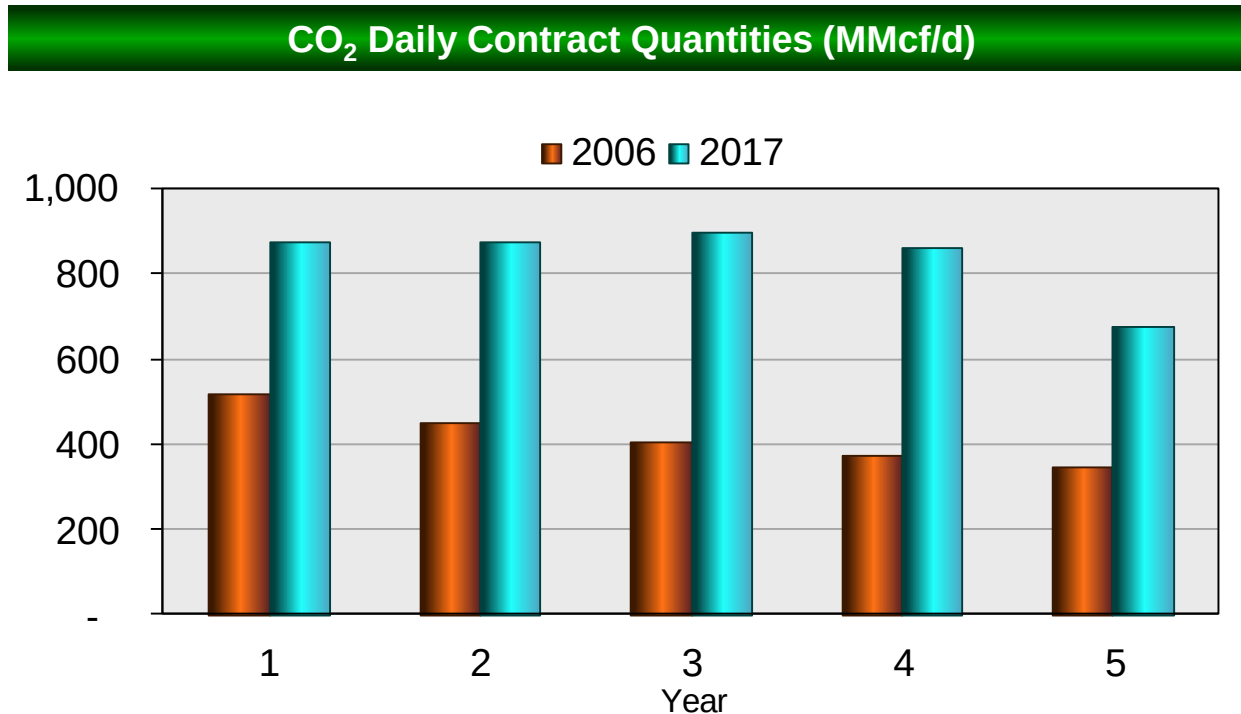
- CAGR: volumes +2.22%
- 2017 vs 2016: volumes -1.49%

As a reminder:

- Sales revenues are based on our working interest entitlement and not deliveries
- KM share of EOR demand consumes ~31% of our entitled production in 2017
- Elimination: consolidation results in eliminating profit on sales to ourselves, however we view our S&T and O&G businesses independently, and price sales to ourselves at market prices

Demand Growth and Regeneration

5-year Contracted CO₂ Volumes

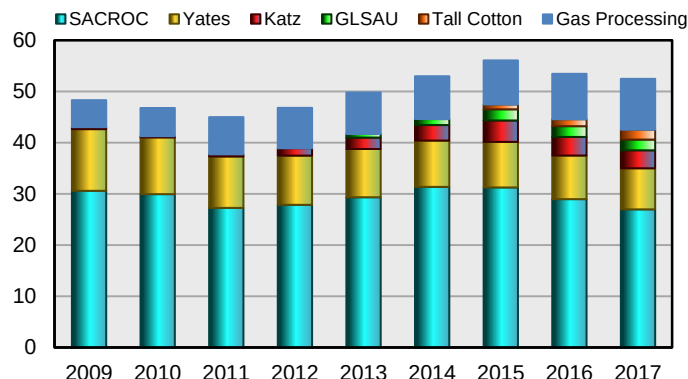


■ Weighted average contract life with 3rd parties is 9.49 years

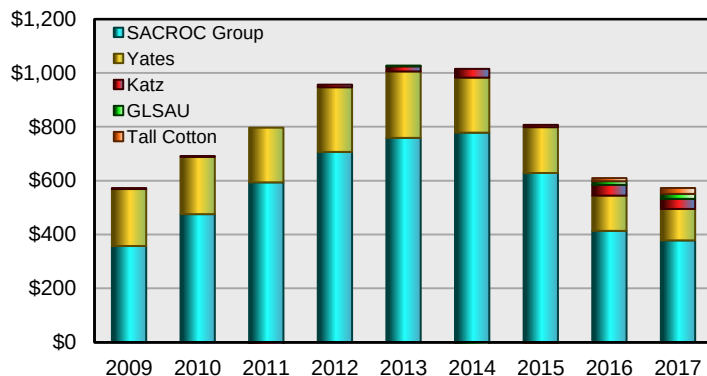
Oil and Gas Segment

Production and DCF

Net Hydrocarbon Production (MBOE/d)



DCF (\$MM)



Original oil in place (Billion Bbls)

SACROC	2.8
Yates	5.0
Katz	0.23
GLSAU	0.48
Tall Cotton	0.70

	Actual 2016	Budget 2017
Gross production (Bbl/d)^(a)		
SACROC oil	29,323	27,478
SGP NGLs	20,925	20,900
Yates	18,368	18,090
Katz	4,054	4,215
GLSAU	1,874	2,310
Tall Cotton	1,078	2,200

	Actual 2016	Budget 2017
DCF^(a) (\$MM, w/o Elim, w/ Alloc Hedges)		
SACROC ^(a,b)	413	378
Yates ^(a)	131	117
Katz	40	37
GLSAU	13	19
Tall Cotton	12	22

Notes: BOE: Oil and NGL =1:1, Residue gas sales = 6:1.

Gas Processing includes net BOE attributable to our plant interests and processing agreements but excluded from reserve report.

(a) Includes Secondary Objectives.

(b) Includes other minor oil and gas properties near SACROC.

CO₂ Oil Production Hedge Profile

■ Hedge our BOE production

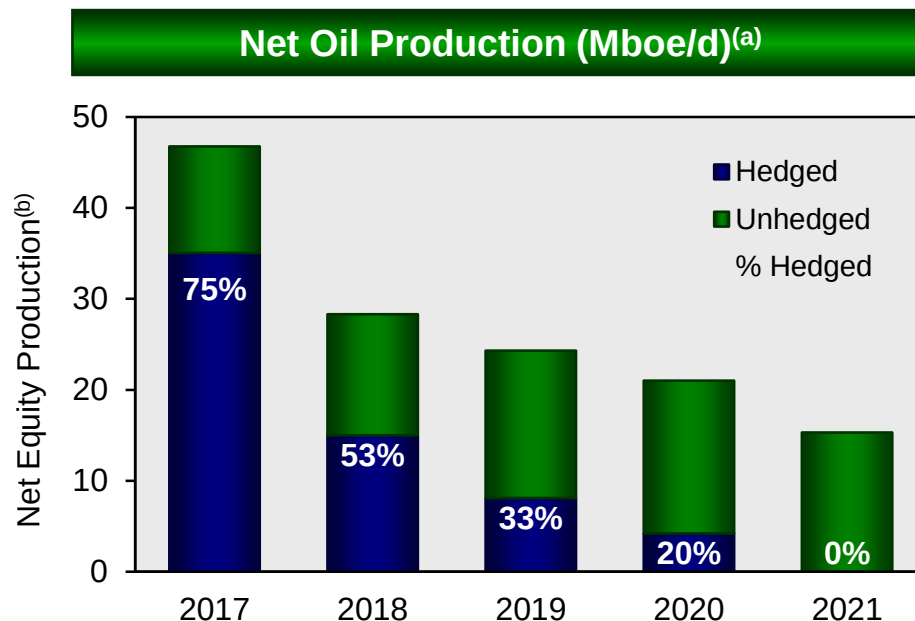
— Targeted minimum hedge amounts:

Current Year: 70%

Year 2: 50%

Year 3: 30%

Year 4: 10%



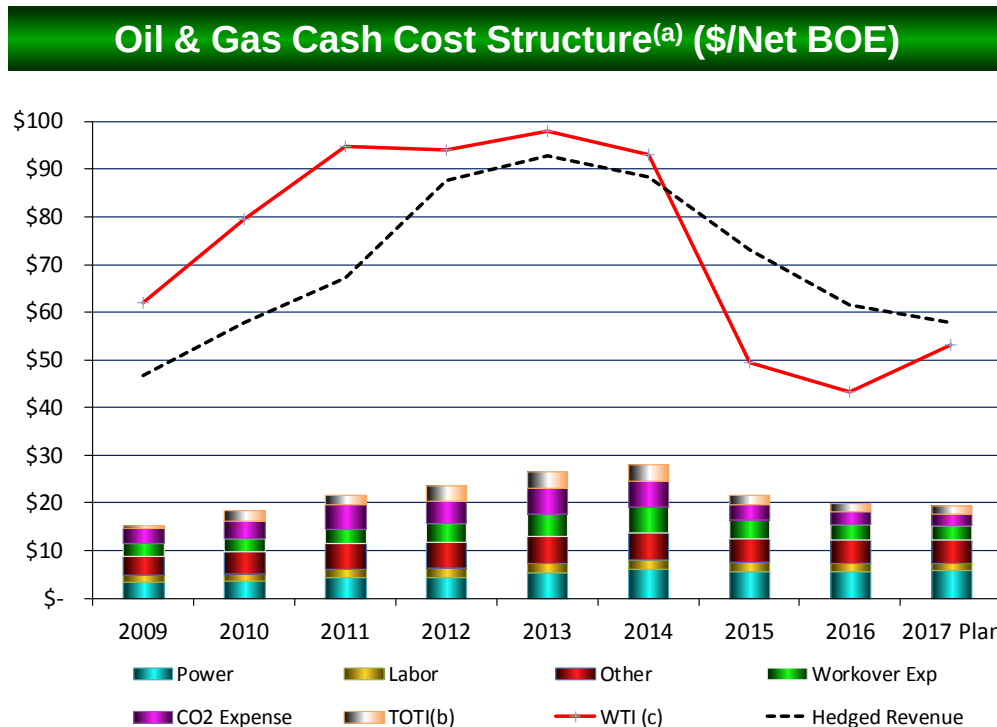
Average hedge price WTI & WTS (\$/Bbl) ^(b)	\$59.02	\$65.30	\$57.38	\$53.43	\$-
Total volume hedged (Mboe/d)	35.1	15.0	8.1	4.2	-
Crude oil swaps	29.1	14.7	8.1	4.2	-
Crude oil puts	4.0	0.3	-	-	-
Propane	2.0	-	-	-	-

(a) Net equity production: 2017 Based on 2017 Budget, 2018 - 2022 based on Ryder Scott reserve report. Includes heavier NGL components (C4+).

(b) Where collars are used, pricing incorporated into average hedge price is the collar floor; for swaps and puts, strike price net of premium is used.

Oil & Gas

Margins and Cost Structure



O&G cost structure has strong correlation to energy prices

- Power is tied to gas prices
- Purchased CO₂ and TOTI^(b) are strongly correlated to oil prices
- Market conditions have decreased material and service costs
- Achieved aggregate operating cost savings of ~35% since 2014

(a) Costs and Revenue per net BOE, including hedges where applicable.

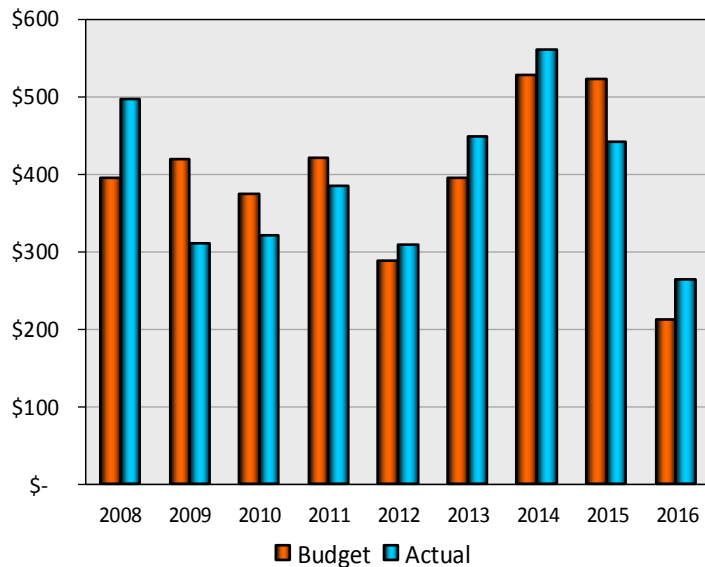
(b) Taxes other than income taxes.

(c) WTI Cushing Price, Source: www.eia.gov.

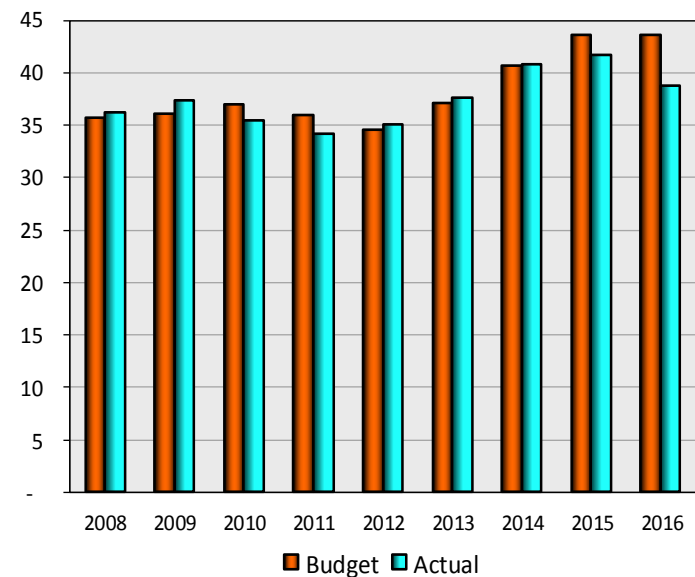
Oil and Gas Segment

Over past 9 years capex 0.5% below plan, oil production 0.8% below plan

Capex (\$MM)



Net Oil Production (MBbl/d)

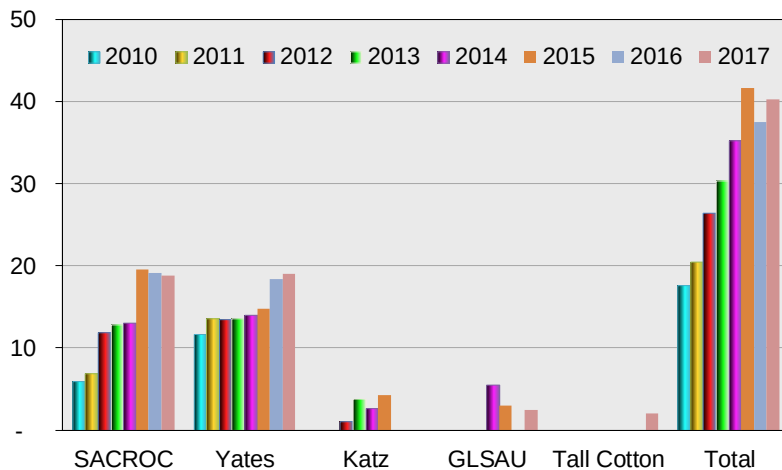


Oil and Gas Segment Production Forecasts

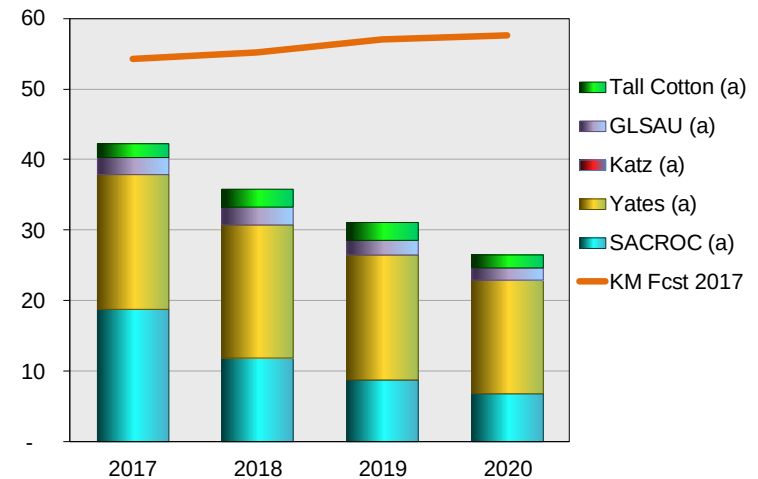
Production expectations tend to grow over time

- **We expect production to exceed our reserve report over the long-term**
 - Higher recoveries and additional targets added to inventory
 - New Technologies

Evolution of Forecasted 2017 Production^(a) over Time (MBbl/d, 8/8ths)



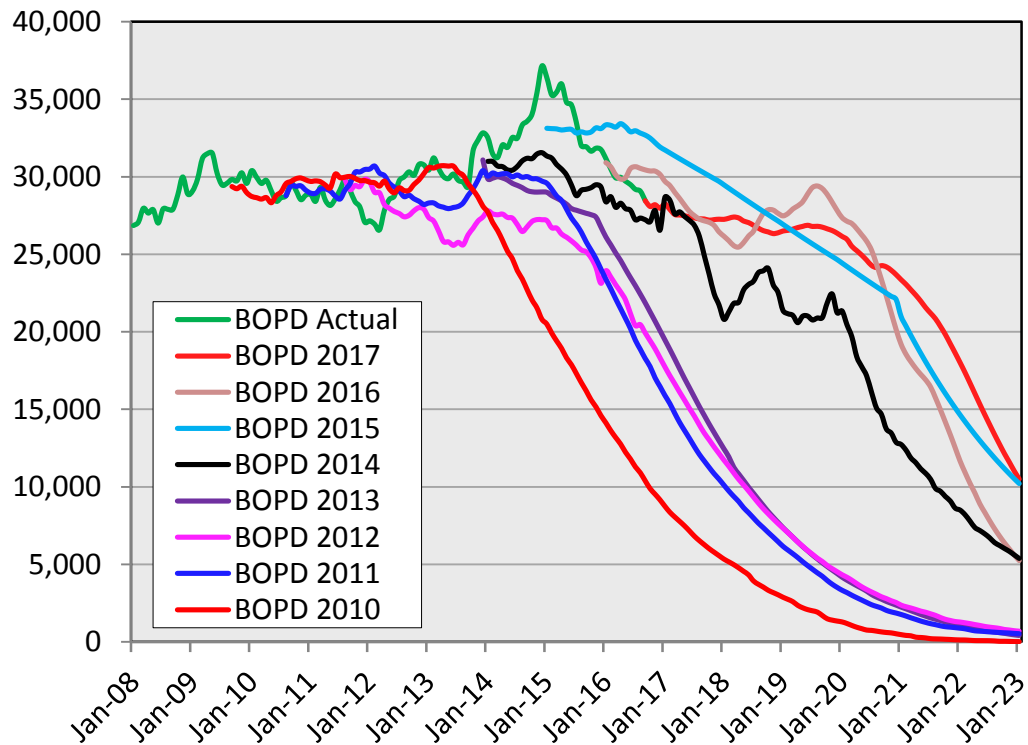
Proved Reserves Production Forecast (MBbl/d, 8/8ths)



(a) Forecasts based on independent consultant reserve report. Excludes minor properties.

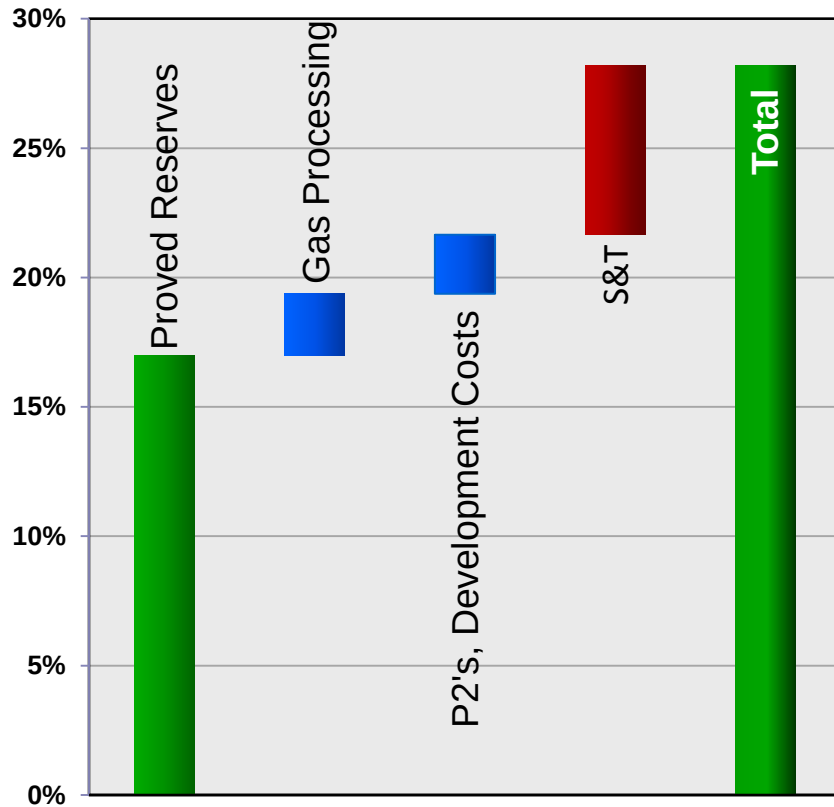
SACROC Unit – Long Range Plan

SACROC Oil Production LRP



- **Changes from 2016 plan**
 - Addition of Hawaii Project
 - Addition of BE PH I Project
 - Infill Timing with CTI's
 - BPP response/timing
- **Examining Transition Zone upside**

Oil & Gas, and Business Unit IRR



All-in O&G IRR (2000-2026): 21.7%

- Proved reserves cash flows: 17.0%
- Adding in Gas Processing excluded from disclosures increases IRR to 19.4%
- Adding in reserves discounted to P2 and using planned development costs increases return to 21.7%

Total business IRR (2000-2026): 28.2%

- Includes S&T assuming volumes increase with higher capacity, valued at market prices

As of 12/31/16, CO₂ Segment cumulative free cash flow is \$4.7B+ (net of cumulative invested capital)

Kinder Morgan Canada

Segment Presentation

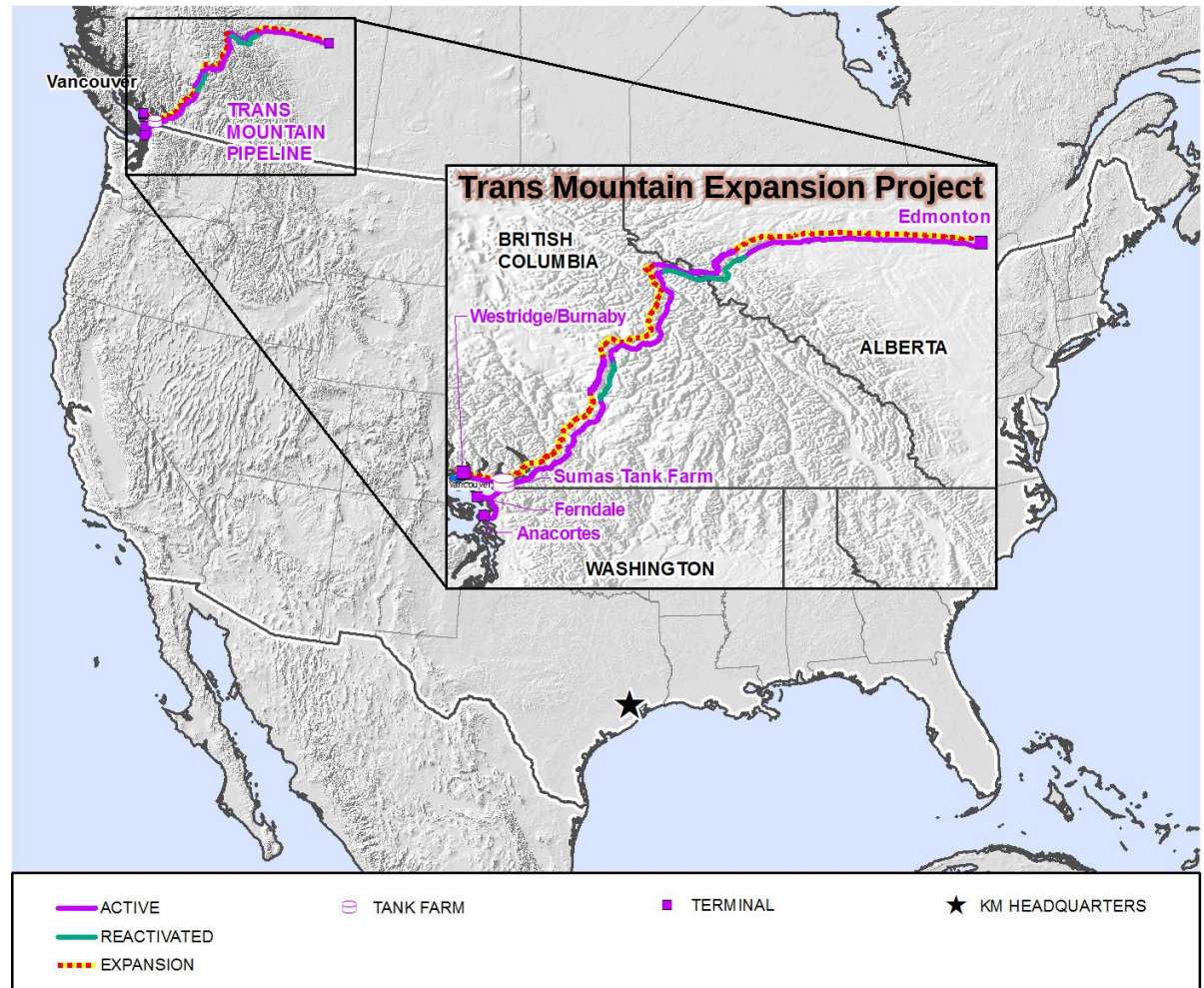
Kinder Morgan Canada

Segment Outlook

Sole oil pipeline from Oilsands to West Coast / export markets

Long-term Growth Drivers:

- Expand Oilsands export capacity to West Coast and Asia
 - Following successful regulatory process, major expansion plans under way
 - The Trans Mountain Pipeline Expansion Project (TMEP) more than doubles capacity, from 300 MBbl/d currently to approximately 890 MBbl/d
 - Strong commercial support from shippers with binding long-term 15 and 20 year contracts for 708 MBbl/d of firm transport capacity
 - Expected in-service end of 2019
- Expanded dock capabilities (Vancouver)
 - TMEP will increase dock capacity to over 600 MBbl/d
 - Access to global markets



Trans Mountain Pipeline



Current Capacity:

- 300 MBbl/d ex-Edmonton
- 241 MBbl/d to Puget Sound

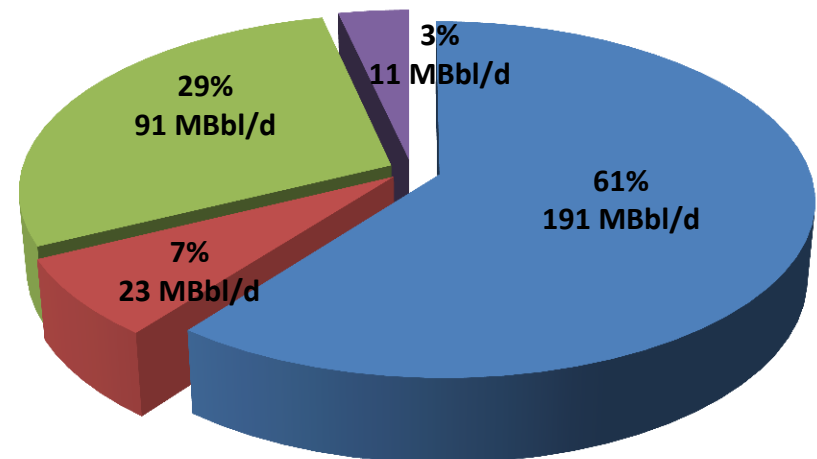
Regulation:

- National Energy Board Regulated
- 2016–2018 toll settlement

Markets:

- British Columbia
 - Crude and Refined Products
- Washington State Refineries
- Westridge Marine Terminal
 - Offshore Markets

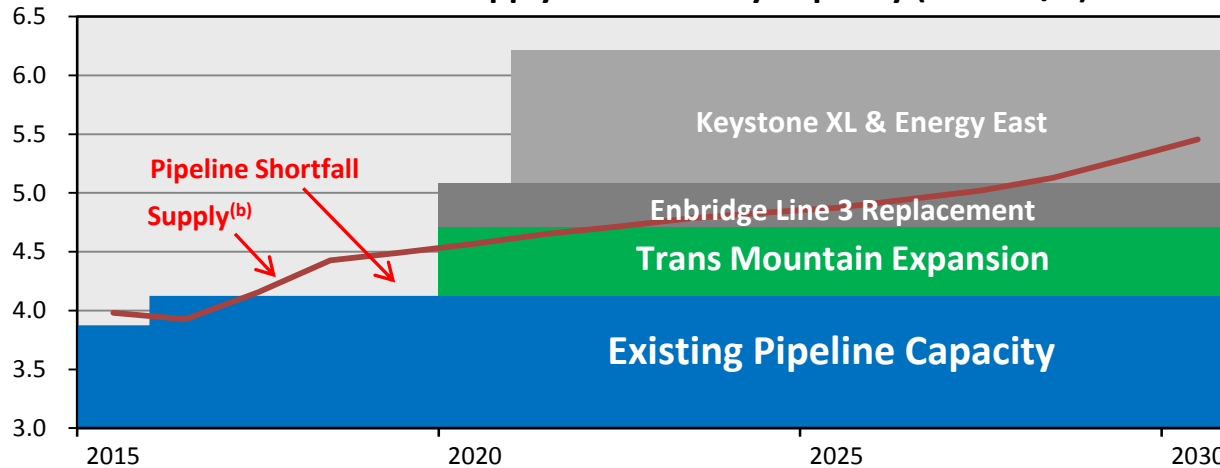
TMPL 2016 Throughput by Destination (MBbl/d)



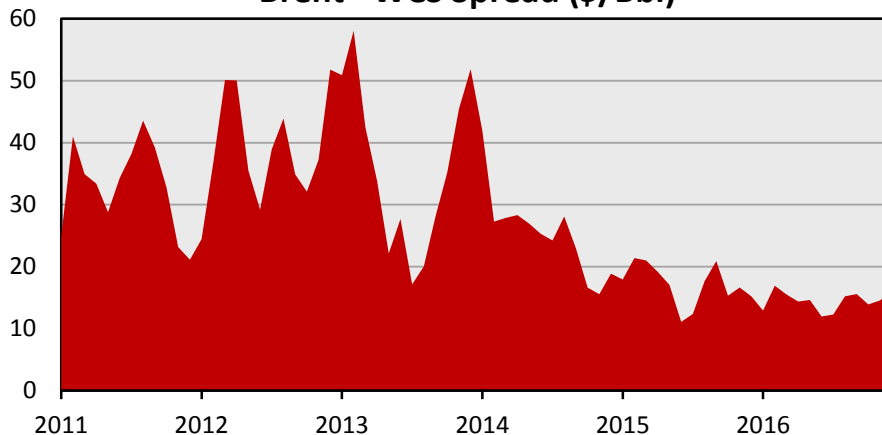
- Puget Sound
- Westridge
- Burnaby
- Kamloops

Market Access Drivers

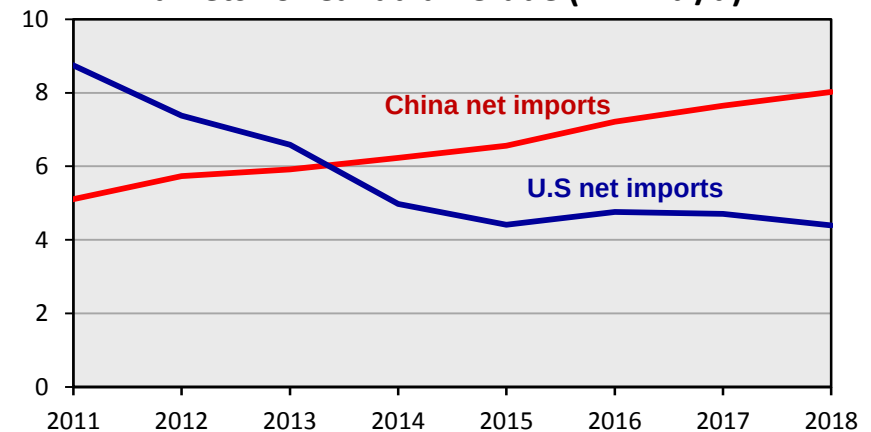
Western Canada Supply vs. Takeaway Capacity (MMBbl/d)^(a)



Brent - WCS Spread (\$/Bbl)^(c)



Markets For Canadian Crude (MMBbl/d)^(d)



(a) Canadian Association of Petroleum Producers (CAPP), 2016 Crude Oil Forecast, Markets & Transportation, June 2016, and KM analysis.

(b) Western Canada supply plus U.S. Bakken movements.

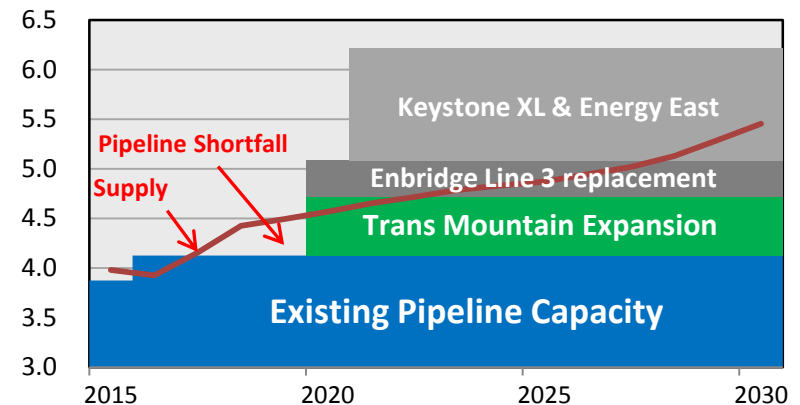
(c) Index Mundi, NGX.

(d) EIA, Short-term Energy Outlook, January 2017.

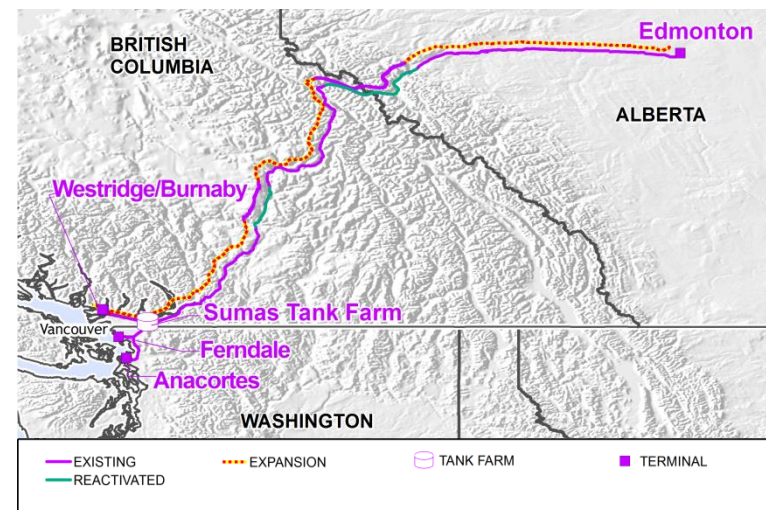
Trans Mountain Expansion Project (TMEP)

- **Expansion to 890 MBbl/d from 300 MBbl/d**
 - 615 miles new pipe; 12 new pump stations
 - 630 MBbl/d tanker export capacity; 3 new berths
 - 20 new tanks
- **13 companies contracted for 708 MBbl/d**
 - 15 & 20 year take-or-pay contracts
 - Commercial terms approved by NEB May 2013
- **Projected Cost**
 - Finalizing cost estimates with contractors
 - Demand remains strong; we expect shippers to remain committed or have other shippers subscribe if final costs are above \$6.8 billion CAD
 - Each \$100mm >\$6.8 billion CAD = ~\$0.07 tariff increase
 - Additional cost pass through protection during construction
 - Substantial development cost protection

Oilsands Supply vs Takeaway Capacity (MMBbl/d)^(a)



Trans Mountain Expansion Project



(a) Canadian Association of Petroleum Producers (CAPP), 2016 Crude Oil Forecast, Markets & Transportation, June 2016, and KM analysis.

Trans Mountain Expansion Project Timeline

2016

- NEB Recommendation May '16
- Federal Approval Dec. '16

2017

- BC Approval Jan. '17
- Cost Review with Shippers Feb. '17
- KM FID 1Q / 2Q 2017
- Begin Construction Sept. '17

2018 – 2019

- Complete Construction, In-Service Dec. '19

Other

Support Slides

Energy Toll Road

Security of Cash

	Natural Gas Pipelines	Products Pipelines	Terminals	CO ₂	Kinder Morgan Canada
■ Volume Security	– Interstate & LNG: take-or-pay – Intrastate: ~77% take-or-pay^(a,b) – G&P: ~88% fee-based^(b) with minimum volume requirements / acreage dedications	– Refined products: primarily volume-based – Crude / liquids: primarily take-or-pay	– Liquids & Jones Act: primarily take-or-pay – Bulk: primarily minimum volume guarantee, or requirements	– S&T: primarily minimum volume guarantee – O&G: volume-based	– Essentially no volume risk
■ Average Remaining Contract Life	– Interstate: 6.2 yrs. – LNG: 15.4 yrs. – Intrastate: 5.3 yrs.^(a) – G&P: 4.2 yrs.	– Refined products: generally not applicable – Crude / liquids: 5.2 yrs.	– Liquids: 3.7 yrs. – Jones Act: 2.8 yrs.^(c) – Bulk: 4.9 yrs.	– S&T: 8.2 yrs.	– 2.0 yrs.^(d)
■ Pricing Security	– Interstate: primarily fixed based on contract – Intrastate: primarily fixed margin – G&P: primarily fixed price	– Refined products: annual FERC tariff escalator (PPI-FG + 1.23%) – Crude / liquids: primarily fixed based on contract	– Based on contract; typically fixed or tied to PPI	– S&T: 83% protected by minimum volumes and floors^(b) – O&G: volumes 75% hedged^(e)	– Fixed based on toll settlement
■ Regulatory Security	– Interstate: regulated return – Intrastate: essentially market-based – G&P: market-based	– Pipelines: regulated return – Terminals & transmix: not price regulated^(f)	– Not price regulated	– Primarily unregulated	– Regulated return
■ Commodity Price Exposure	– Interstate: no direct exposure – Intrastate: limited exposure – G&P: limited exposure	– Minimal, limited to transmix business	– No direct exposure	– Full-yr 2017: \$4.4MM in DCF per \$1/Bbl change in oil price	– No direct exposure

All figures as of 1/1/2017, unless otherwise noted.

(a) Includes term sale portfolio.

(b) Based on KMI 2017 budgeted Segment EBDA before Certain Items and including KM-share of Certain Equity Investee DD&A where applicable (non-GAAP measure).

(c) Jones Act vessels: average remaining contract term for operating tankers (12) and tankers under construction (4) is 2.8 years, or 4.1 years including options to extend.

(d) Provisions in TMPL's negotiated toll settlement allow for the parties to extend the agreement to coincide with in-service of the Trans Mountain expansion project, expected at end of 2019.

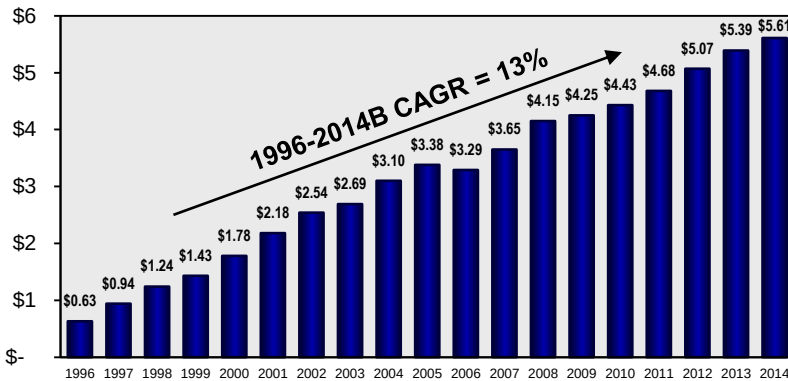
(e) Percentage of 2017 budgeted net crude oil, propane and heavy NGL (C4+) net equity production.

(f) Terminals not FERC regulated, except portion of CALNEV.

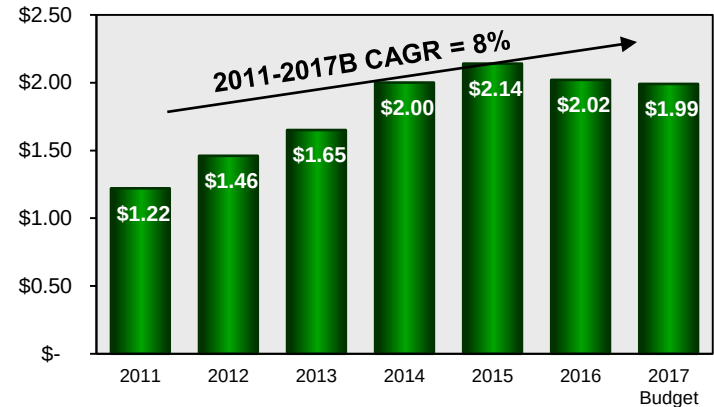
Two Decades of Stable Growth

Strategy Has Led to Consistent, Growing Results

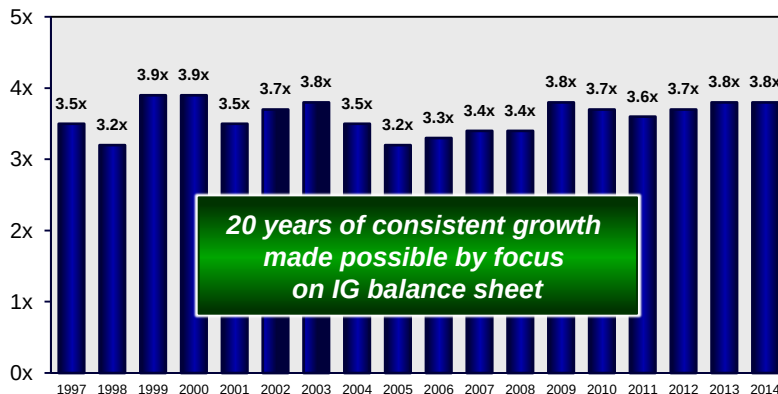
KMP Annual LP DCF per Unit^(a)



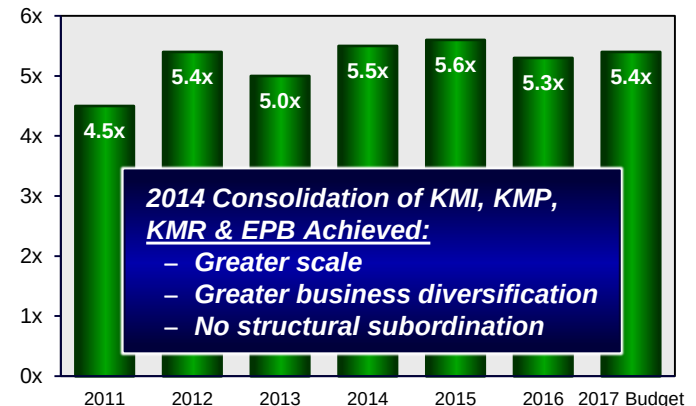
KMI Annual DCF per Common Share



KMP Net Debt/Adjusted EBITDA^(b)



KMI Net Debt/Adjusted EBITDA^(b)



Notes: DCF and Adjusted EBITDA are before Certain Items (non-GAAP measures). 2017 per budget. See Appendix for defined terms and reconciliations to GAAP measures.

KMP was Kinder Morgan's primary investment vehicle and held the majority of operating assets from 1996 to 2014.

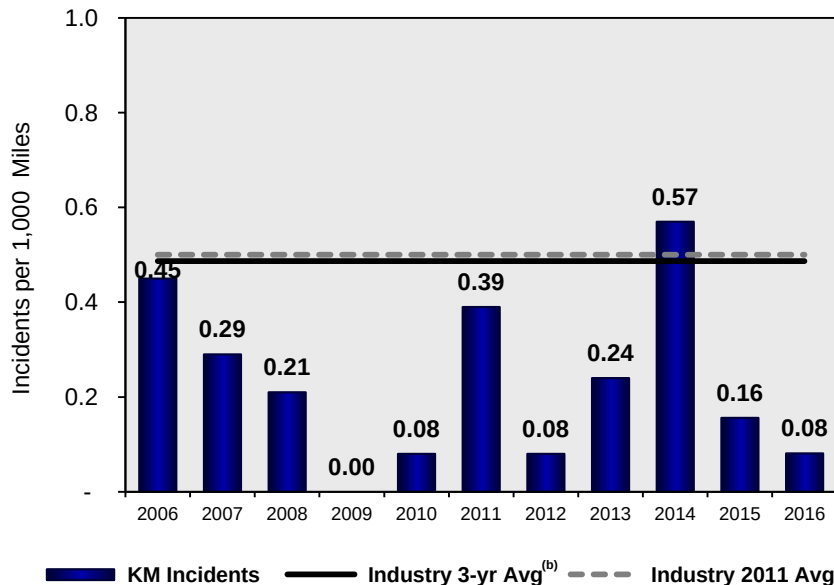
(a) KMP annual LP DCF per share. 2014 data per budget as KMP was acquired by KMI prior to close of 4Q 2014. Assumes full distribution of DCF per unit for 1996-1999.

(b) Debt is net of cash and excludes fair value adjustments. KMP 2014 as of 9/30/2014.

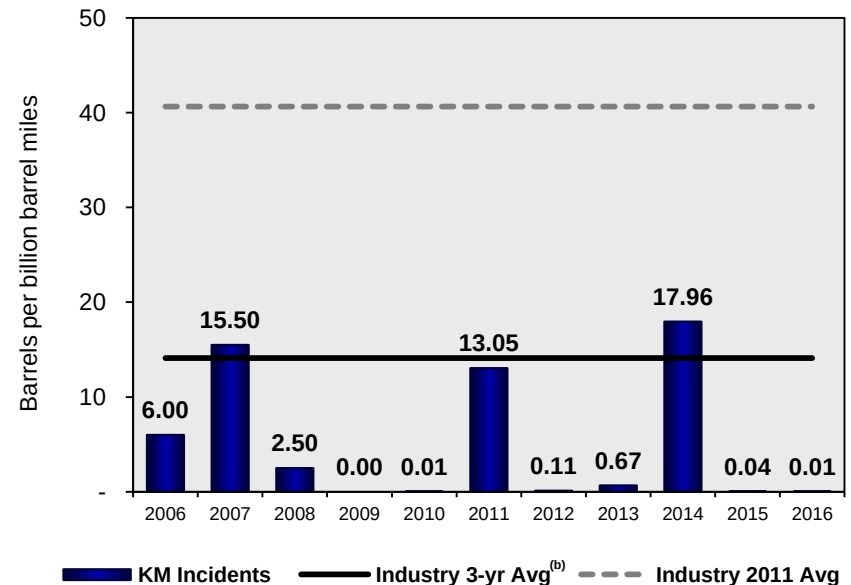
Incidents & Releases

Liquids Pipeline Right-of-way

**Liquids Pipelines
Incidents per 1,000 Miles^(a)**



**Liquids Pipelines
Release Rate^(a)**



Note: KM totals exclude non-DOT jurisdictional CO₂ Gathering and Crude Gathering for compatibility with industry comparisons.

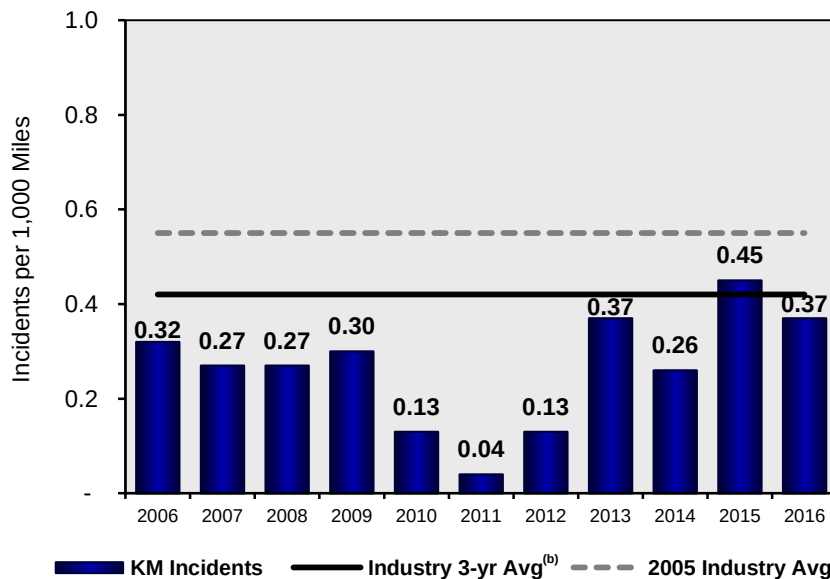
(a) Failures involving onshore pipelines that occurred on the ROW, including valve sites, in which there is a release of the liquid or carbon dioxide transported resulting in any of the following:

- Explosion or fire not intentionally set by the operator.
 - Release 5 barrels or greater. (NOTE: PHMSA does not record system location for releases less than 5 barrels)
 - Death of any person.
 - Personal injury necessitating hospitalization.
 - Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding \$50,000; not included: natural gas transportation assets.
- (b) 2013–2015 most recent PHMSA 3-yr average available.

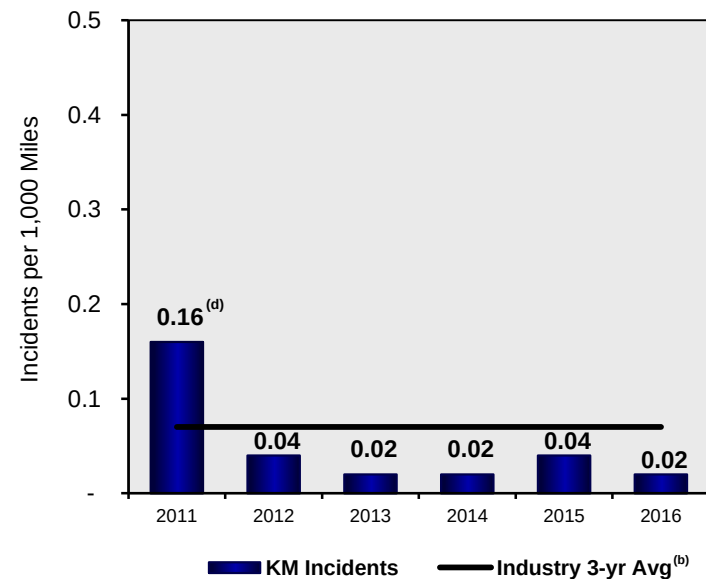
Incidents & Releases

Natural Gas Pipeline Right-of-way

**Natural Gas Pipelines
Incidents Rate All Reportable Incidents^(a)**



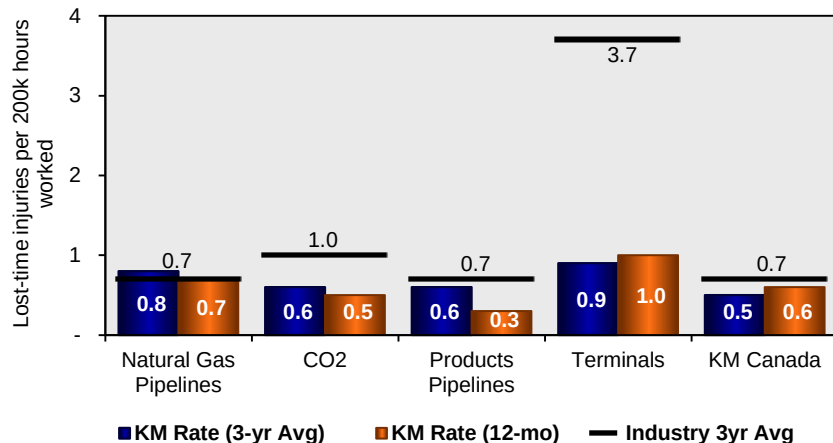
**Natural Gas Pipelines
Incidents Rate Onshore Ruptures-only^(c)**



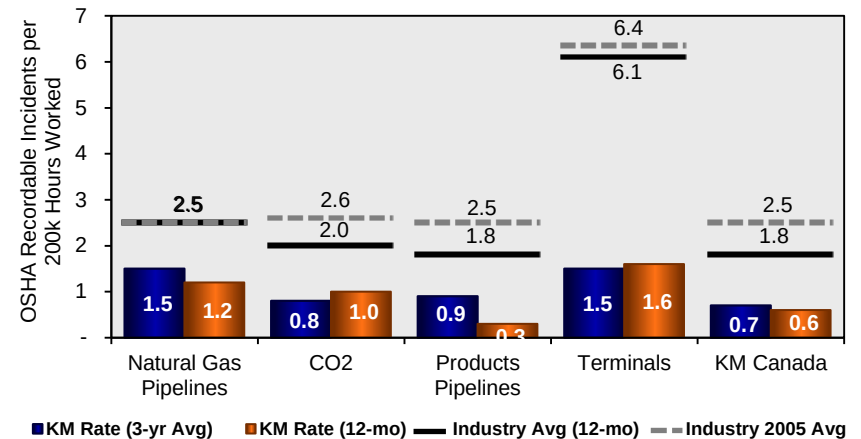
- (a) Excludes El Paso and Copano assets in periods prior to acquisition (El Paso 5/25/2012, Copano 5/1/2013). An Incident means any of the following events:
- An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:
 - i. A death or personal injury necessitating in-patient hospitalization; or
 - ii. Estimated property damage of \$50,000 or more, including loss to the operator and others, but excluding cost of gas lost (2010 and earlier rates include cost of gas lost)
 - iii. 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 of paragraphs (1) or (2) above.
- (b) 2013–2015 most recent PHMSA 3-yr 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^(a)

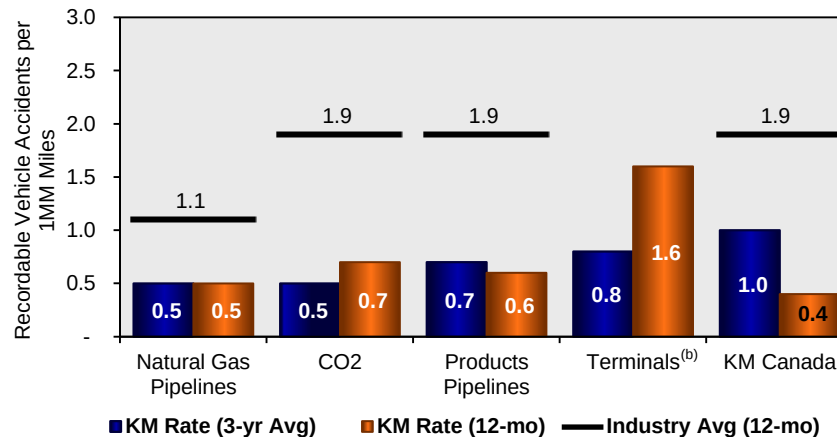
KM Lost-time Incident Rate (DART)



OSHA Recordable Incident Rate



Vehicle Incident Rate



(a) 12-month safety performance summary as of 12/31/2016.

(b) Industry average not available for Terminals.

Definitions and GAAP Reconciliations

Use of Non-GAAP Financial Measures

The non-generally accepted accounting principles (non-GAAP) financial measures of distributable cash flow (DCF), both in the aggregate and per share, segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments (DD&A) and Certain Items (Segment EBDA before Certain Items), net income before interest expense, taxes, DD&A and Certain Items (Adjusted EBITDA), and adjusted earnings (Adjusted Earnings), both in the aggregate and per share, are presented herein. Our non-GAAP measures described above should not be considered alternatives to GAAP net income or other GAAP measures and have important limitations as analytical tools. Our computations of DCF, Segment EBDA before Certain Items, Adjusted EBITDA and Adjusted Earnings 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 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. Reconciliations of DCF, Segment EBDA before Certain Items, Adjusted EBITDA and Adjusted Earnings to their most directly comparable GAAP financial measures are included herein.

Certain Items 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, hurricane impacts and casualty losses).

DCF is a significant performance measure used by us and by external users of our financial statements to evaluate our performance and to measure and estimate the ability of our assets to generate cash earnings after servicing our debt and preferred stock dividends, 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. Management uses this measure and believes it provides users of our financial statements a useful measure reflective of our business's ability to generate cash earnings to supplement the comparable GAAP measure. We believe the GAAP measure most directly comparable to DCF is net income available to common stockholders. DCF per share is DCF divided by average outstanding common shares and restricted stock awards that participate in dividends.

Use of Non-GAAP Financial Measures (Cont'd)

Segment EBDA before Certain Items is used by management in its analysis of segment performance and management of our business. General and administrative expenses 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 Segment EBDA before Certain Items is a significant performance metric because it provides us 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 Segment EBDA before Certain Items is segment earnings before DD&A and amortization of excess cost of equity investments (Segment EBDA). Segment EBDA before Certain Items is calculated by adjusting Segment EBDA for the Certain Items attributable to a segment, which are specifically identified in the footnotes to the accompanying tables when reported.

Adjusted EBITDA is used by management and external users, in conjunction with our net debt, 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. Adjusted EBITDA is calculated by adjusting net income before interest expense, taxes, and DD&A (EBITDA) for Certain Items, noncontrolling interests before Certain Items, and KMI's share of Certain Equity Investees' DD&A and book taxes, which are specifically identified in the footnotes to the accompanying tables when reported.

Adjusted Earnings is used by certain external users of our financial statements to assess the earnings of our business excluding Certain Items as another reflection 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 is Adjusted Earnings divided by Average Adjusted Common Shares which include KMI's weighted average common shares outstanding, unvested restricted shares that contain rights to dividends (which may not be dilutive under GAAP) and any shares resulting from dilutive impact of warrants under treasury stock method.

Budgeted Net Income is not provided (the GAAP financial measure most directly comparable to DCF and Adjusted EBITDA) due to the inherent difficulty and impracticability of predicting certain amounts required by GAAP, such as ineffectiveness on commodity, interest rate and foreign currency hedges, unrealized gains and losses on derivatives marked to market, and potential changes in estimates for certain contingent liabilities.

Certain Equity Investees, for the periods during which these are accounted for as equity method investments, include Plantation, Cortez, SNG, ELC, MEP, FEP, EagleHawk, Red Cedar, Bear Creek, Cypress, Parkway, Sierrita, Bighorn, Fort Union, Webb/Duvall, Liberty, Double Eagle, Endeavor, WYCO, GLNG, Ruby, Young Gas, Citrus, NGPL and others. DD&A and sustaining capex for Plantation and Cortez were made beginning in 2017. For joint ventures consolidated by KMI, JV DD&A and sustaining capex are net of our partners' share of these items.

GAAP Reconciliation

(\$ in millions)

	Yr. Ended 12/31/16
Reconciliation of DCF	
Net Income	\$ 721
Certain Items	933
Net Income before Certain Items (Adjusted Earnings)	1,654
DD&A	2,268
JV DD&A ^(a)	349
Book taxes ^(b)	993
Cash taxes	(79)
Noncontrolling interests ^(c)	(21)
Sustaining capex including KMI share of JV sustaining capex	(540)
Other ^(e)	43
Distributable Cash Flow (DCF) attributable to Kinder Morgan, Inc.	4,667
Preferred stock dividends	(156)
DCF attributable to Common Stockholders	\$ 4,511
Reconciliation of Segment EBDA before Certain Items	
Segment EBDA before DD&A	\$ 6,366
Certain Items impacting segments	1,119
Segment EBDA before Certain Items	7,485
Reconciliation of net debt	
Long-term debt excluding fair value adjustments ^(f)	\$ 36,148
Current portion of debt	2,696
Less: cash & equivalents	(684)
Net debt	\$ 38,160

	Yr. Ended 12/31/16
Reconciliation of Adjusted EBITDA	
Net Income	\$ 721
Certain Items	933
Net Income before Certain Items (Adjusted Earnings)	1,654
Book taxes ^(b)	993
Noncontrolling interests ^(c)	(21)
DD&A	2,268
JV DD&A ^(a)	349
Interest, net before Certain Items	1,999
Adjusted EBITDA	\$ 7,242

Certain Items	
Acquisition related costs	\$ 13
Fair value amortization	(143)
Contract early termination revenue	(57)
Legal and environmental reserves	(16)
Mark to market and ineffectiveness	75
Loss on impairments and divestitures, net	848
Project write-offs	171
Other ^(g)	24
Subtotal	915
Book taxes on Certain Items	18
Total Certain Items	\$ 933

Note: Definitions for defined terms found in the Appendix.

(a) Includes KMI share of Certain Equity Investees DD&A.

(b) Includes KMI share of Certain Equity Investee book taxes of \$94 million, and excludes book taxes on Certain Items of \$13 million.

(c) Before Certain Items. Represents net income allocated to third-party ownership interests in consolidated subsidiaries.

(d) Includes KMI share of Certain Equity Investee sustaining capital expenditures \$90 million.

(e) Consists primarily of book to cash timing differences related to certain defined benefit plans partially offset by retiree medical contributions.

(f) Excludes Kinder Morgan G.P. Inc.'s \$100 million preferred stock due 2057 and (\$43) million non-cash foreign exchange impact on KMI's Euro-denominated debt.

(g) 2016 Other Certain Items include \$14 million employee right-sizing, \$5 Nassau crane incident, \$4 Berry bankruptcy, \$4 CBS closure, (\$4) mark to market power contract adjustment and \$1 other.

Explanation of Return Calculations

	Formula	Notes
Segment Return on Investment	Segment EBDA before Certain Items 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)

- (a) Adjustments are made to Segment EBDA to more closely tie to cash: (1) our share of JV DD&A for Certain Equity Investees 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 (2015-2016).
- (b) Annual average of the quarterly Total Investment.
- (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 Segment EBDA before Certain Items less sustaining capex and G&A. Thereafter, this item is defined as the sum of the individual Segment EBDA before Certain Items less sustaining capex, less G&A and cash taxes, plus book taxes deducted at the segment level and KMI's share of c-corp equity investee's book taxes.
- (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 sustaining capital expenditures for Certain Equity Investees, less equity earnings plus cash distributions received for Express and Endeavor (1H 2014 and prior), additional other equity investees, plus the general partner's incentive and the general partner non-controlling interest, as applicable. Thereafter, DCF is defined as net income available to common stockholders before Certain Items plus DD&A and book taxes, less cash taxes and sustaining capital expenditures, plus KMI's share of JV DD&A less sustaining capital expenditures for Certain Equity Investees, plus/minus other items (primarily an add-back for non-cash compensation, less retirement benefits). Book and cash taxes include KMI's share of its C-corp equity investees.
- (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 also includes DCF spent to fund growth capital.

	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)

- (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 Products 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) For KMI's 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 as GAAP financials revalue the entire asset balance based on the end of period exchange rate.

Investor Relations Contacts

Institutional Investors / Sell-side Analysts

David Michels	VP Finance & Investor Relations	(713) 369-9895	david_michels@kindermorgan.com
Peter Staples	Director Investor Relations	(713) 369-9221	peter_staples@kindermorgan.com

Retail Investors / Brokers

Miguel Garcia	Investor Relations Analyst	(713) 420-5269	miguel_garcia@kindermorgan.com
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