Run For Shareholders, By Shareholders

Kimberly Dang
CFO

March 9, 2016
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; capital and credit markets conditions; 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 our Analyst Day presentation, dated 1/27/2016, on our website at www.kindermorgan.com. These non-GAAP measures should not be considered an alternative to GAAP financial measures.
Unparalleled Asset Footprint

Largest Energy Infrastructure Company in North America

World class asset footprint:

- Largest natural gas pipeline network in North America
  - Own an interest in / operate over 69,000 miles of natural gas pipeline
  - Connected to every important U.S. natural gas resource play, including: Eagle Ford, Marcellus, Utica, Bakken, Uinta, Haynesville, Fayetteville and Barnett

- Largest independent transporter of petroleum products in North America
  - Transport ~2.1 MMBbl/d\(^{(a)}\)

- Largest CO\(_2\) transporter in North America
  - Transport ~1.2 Bcf/d of CO\(_2\)\(^{(a)}\)

- Largest independent terminal operator in North America\(^{(b)}\)
  - Own an interest in / operate ~180 liquids / dry bulk terminals
  - ~152 MMBbls of liquids capacity
  - Handle ~65 MMtons of dry bulk products\(^{(a)}\)
  - Strong Jones Act shipping position

- Only Oilsands pipeline serving West Coast
  - Transports ~300 MBBbl/d to Vancouver / Washington State; proposed expansion takes capacity to 890 MBBbl/d

Footprint drives growth project pipeline:

- $18.2 billion 5-year growth capex program
  - Secured by long-term contracts
  - Attractive, fee-based returns

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\(^{(a)}\) 2016 budget.
\(^{(b)}\) Includes KMI / BP JV terminals.
KMI Overview
Management Aligned with Investors; 14% Stake in KMI

Simple Public Structure

- Management / Original S/H (14%)
- Public Float (86%)

Simple Structure:
- One equity base
- One dividend policy
- One debt rating
- No structural subordination
- No incentive distribution rights

Kinder Morgan, Inc.
(C-corp, NYSE: KMI)

Market Equity: $43.0B
Net Debt: 41.2B
Enterprise Value: $84.2B

2016E Dividend per Share: $0.50
Credit Rating: BBB– / Baa3 / BBB–

(a) Includes Form-4 filers and unvested restricted shares.
(b) Market prices as of 3/4/2016; KMI market equity based on ~2,237 million shares outstanding (including restricted shares) at a price of $18.52, ~293 million warrants at a price of $0.08, and 32 million mandatorily convertible depositary shares at a price of $46.25.
(c) Debt of KMI and its consolidated subsidiaries as of 12/31/2015, 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 2016 budget.
(e) KMI corporate credit ratings from S&P (Stable outlook), Moody’s (Stable) and Fitch (Stable), respectively.
Our Strategy

- **Focus on stable fee-based assets that are core to North American energy infrastructure**
  - Market leader in each of our business segments

- **Maintaining a strong balance sheet is paramount**
  - Our primary investing entity has been investment grade for our entire 19-year history
  - Reduced dividend demonstrates our commitment to investment grade

- **Control costs**
  - It’s investors’ money, not management’s – treat it that way

- **Leverage asset footprint to seek attractive capital investment opportunities, both expansion and acquisition**
  - Since 1997, Kinder Morgan has completed approximately $29 billion in acquisitions and invested approximately $25 billion in greenfield / expansion projects\(^{(a)}\)

- **Transparency to investors**

- **Keep it simple**

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19 Years of Stable Growth
Strategy Has Led to Consistent, Growing Results

KMP Annual LP DCF per Unit (a)

KMI Annual DCF per Common Share (c)

KMP Net Debt to EBITDA (b)

KMI Net Debt to EBITDA (b)

Notes:
Excludes certain items. 2016 per budget.
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.
(c) The terms “DCF” and “DCF per share” mean cash available to common shareholders (i.e., after payment of preferred dividend).
Capital Invested
~$54 Billion of Asset Investment & Acquisitions Since Inception\(^{(a,c)}\)

\((\$ \text{ in billions})\)

**Total Invested by Year\(^{(b,c)}\)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Expansion ($ billion)</th>
<th>Acquisition ($ billion)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1998</td>
<td>$1.6</td>
<td>$0.0</td>
</tr>
<tr>
<td>1999</td>
<td>$1.0</td>
<td>$1.1</td>
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<tr>
<td>2000</td>
<td>$2.1</td>
<td>$0.9</td>
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<tr>
<td>2001</td>
<td>$1.5</td>
<td>$1.2</td>
</tr>
<tr>
<td>2002</td>
<td>$0.9</td>
<td>$1.1</td>
</tr>
<tr>
<td>2003</td>
<td>$1.1</td>
<td>$0.9</td>
</tr>
<tr>
<td>2004</td>
<td>$2.4</td>
<td>$2.9</td>
</tr>
<tr>
<td>2005</td>
<td>$2.9</td>
<td>$3.3</td>
</tr>
<tr>
<td>2006</td>
<td>$2.5</td>
<td>$2.6</td>
</tr>
<tr>
<td>2007</td>
<td>$2.5</td>
<td>$2.6</td>
</tr>
<tr>
<td>2008</td>
<td>$2.4</td>
<td>$2.9</td>
</tr>
<tr>
<td>2009</td>
<td>$3.3</td>
<td>$3.3</td>
</tr>
<tr>
<td>2010</td>
<td>$6.5</td>
<td>$6.5</td>
</tr>
<tr>
<td>2011</td>
<td>$9.8</td>
<td>$9.8</td>
</tr>
<tr>
<td>2012</td>
<td>$5.8</td>
<td>$5.8</td>
</tr>
<tr>
<td>2013</td>
<td>$6.6</td>
<td>$6.6</td>
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<tr>
<td>2014</td>
<td>$3.3</td>
<td>$3.3</td>
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<tr>
<td>2015</td>
<td>$2.4</td>
<td>$2.4</td>
</tr>
<tr>
<td>2016</td>
<td>$2.5</td>
<td>$2.5</td>
</tr>
<tr>
<td>Budget</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Total Invested by Type\(^{(a,c)}\)**

- **Expansions**
  - 1997-2015: $25.0 billion
- **Acquisitions**
  - 1997-2015: $28.8 billion

**Total Invested by Segment\(^{(a,c)}\)**

- **Natural Gas Pipelines**
  - 1997-2015: $28.9 billion
- **Products Pipelines**
  - 1997-2015: $7.4 billion
- **Terminals**
  - 1997-2015: $9.1 billion
- **CO2**
  - 1997-2015: $7.1 billion
- **Kinder Morgan Canada**
  - 1997-2015: $1.3 billion

\(\text{Note: Includes equity contributions to joint ventures.}\)
\(\quad \text{(a) 1997-2015; represents investment of KMP (1997-2014), EPB (2013-2014), and KMI (2015).}\)
\(\quad \text{(b) 1997-2016B; represents investment of KMP (1997-2014), EPB (2013-2014), and KMI (2015-2016B).}\)
\(\quad \text{(c) Net of proceeds from 2012 FTC Rockies divestiture in Natural Gas Pipelines segment. Excludes ~}$11.3\text{ billion in EPB asset acquisitions prior to KMI’s acquisition of El Paso, but which is included in our ROI calculation.}\)
\(\quad \text{Includes approximately $800 million Products Pipelines segment legal settlement and reserves incurred over the past decade, but which is included in our ROI calculation.}\)
### Returns on Invested Capital

**Consistent Returns Demonstrate Asset Performance, Management Discipline**

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas Pipes</td>
<td>13.3%</td>
<td>15.5%</td>
<td>12.9%</td>
<td>13.5%</td>
<td>14.0%</td>
<td>15.5%</td>
<td>16.7%</td>
<td>17.5%</td>
<td>16.9%</td>
<td>14.0%</td>
<td>11.9%</td>
<td>11.9%</td>
<td>11.9%</td>
<td>10.9%</td>
<td>10.9%</td>
<td>10.3%</td>
</tr>
<tr>
<td>Products Pipelines</td>
<td>11.9%</td>
<td>11.8%</td>
<td>12.8%</td>
<td>12.9%</td>
<td>12.4%</td>
<td>11.6%</td>
<td>11.8%</td>
<td>13.2%</td>
<td>12.5%</td>
<td>13.4%</td>
<td>13.7%</td>
<td>12.9%</td>
<td>12.1%</td>
<td>12.4%</td>
<td>12.3%</td>
<td>12.6%</td>
</tr>
<tr>
<td>Terminals</td>
<td>19.1%</td>
<td>18.2%</td>
<td>17.7%</td>
<td>18.4%</td>
<td>17.8%</td>
<td>16.9%</td>
<td>17.1%</td>
<td>15.8%</td>
<td>15.5%</td>
<td>15.1%</td>
<td>14.6%</td>
<td>14.3%</td>
<td>13.5%</td>
<td>12.1%</td>
<td>11.2%</td>
<td>10.2%</td>
</tr>
<tr>
<td>CO₂</td>
<td>27.5%</td>
<td>24.6%</td>
<td>22.0%</td>
<td>21.9%</td>
<td>23.8%</td>
<td>25.7%</td>
<td>23.1%</td>
<td>21.7%</td>
<td>25.4%</td>
<td>23.1%</td>
<td>25.3%</td>
<td>25.9%</td>
<td>28.1%</td>
<td>25.9%</td>
<td>22.8%</td>
<td>16.2%</td>
</tr>
<tr>
<td>KM Canada</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>11.0%</td>
<td>12.1%</td>
<td>12.8%</td>
<td>13.7%</td>
<td>14.1%</td>
<td>16.3%</td>
<td>14.8%</td>
<td>11.5%</td>
</tr>
<tr>
<td>Return on Investment</td>
<td>12.3%</td>
<td>12.7%</td>
<td>12.6%</td>
<td>13.1%</td>
<td>13.6%</td>
<td>14.3%</td>
<td>14.4%</td>
<td>14.1%</td>
<td>14.8%</td>
<td>13.9%</td>
<td>13.5%</td>
<td>13.5%</td>
<td>13.6%</td>
<td>11.9%</td>
<td>11.4%</td>
<td>10.3%</td>
</tr>
</tbody>
</table>

| 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%| 14.3%|

**Notes:** Reflects KMP (2000–2012), KMP and EPB (2013–2014) and KMI (2015). A definition of these measures may be found in the Appendix to our Analyst Day presentation, dated 1/27/2016, on our website at [www.kindermorgan.com](http://www.kindermorgan.com).

(a) G&A is deducted to calculate the combined ROI, 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% and 10.5% in 2013, 2014 and 2015, respectively.

(c) Includes NGPL and Citrus investments.
**2016 Budget Guidance**

*Supported by Diversified, Fee-based Cash Flow*

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**2016 Budget**

- KMI 2016 budgeted distributable cash flow available to common shareholders of $4.7 billion
  - 2016 declared dividend of $0.50 per share
  - ~$3.6 billion of cash in excess of dividend
- Growth capex of $3.3 billion in expansions, JV contributions, and acquisitions
- Segment EBDA of $8.0 billion\(^{(a)}\)
- Year-end 2016 debt to EBITDA ratio of 5.5x
- 2016 budget assumes WTI oil price of $38/Bbl and natural gas price of $2.50/MMBtu\(^{(b)}\)
  - $1/Bbl change in oil price = ~$6.5 million DCF impact
  - 10c/MMBtu change in natural gas price = ~$0.6 million DCF impact
  - 1% change in NGL/WTI ratio = ~$2.0 million DCF impact

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**Commodity Price Sensitivity**

- 2016 budgeted coverage of $3.6 billion over declared dividends
- Expected 2016 dividend coverage under various commodity price scenarios:

<table>
<thead>
<tr>
<th>WTI Oil Price ($/Bbl)</th>
<th>$60</th>
<th>$50</th>
<th>$38</th>
<th>$30</th>
<th>$20</th>
</tr>
</thead>
<tbody>
<tr>
<td>$3.00</td>
<td>$3,717</td>
<td>$3,652</td>
<td>$3,574</td>
<td>$3,522</td>
<td>$3,457</td>
</tr>
<tr>
<td>$2.75</td>
<td>$3,715</td>
<td>$3,650</td>
<td>$3,572</td>
<td>$3,520</td>
<td>$3,455</td>
</tr>
<tr>
<td><strong>$2.50</strong></td>
<td>$3,714</td>
<td>$3,649</td>
<td><strong>$3,571</strong></td>
<td>$3,519</td>
<td>$3,454</td>
</tr>
<tr>
<td>$2.25</td>
<td>$3,712</td>
<td>$3,647</td>
<td>$3,569</td>
<td>$3,517</td>
<td>$3,452</td>
</tr>
<tr>
<td>$2.00</td>
<td>$3,711</td>
<td>$3,646</td>
<td>$3,568</td>
<td>$3,516</td>
<td>$3,451</td>
</tr>
<tr>
<td>$1.75</td>
<td>$3,709</td>
<td>$3,644</td>
<td>$3,566</td>
<td>$3,514</td>
<td>$3,449</td>
</tr>
</tbody>
</table>

- Sensitivities based on **full-year** average price changes from budget
- Sensitivities intended to be an approximation only

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Note: Excludes certain items.

\(^{(a)}\) Includes KM-share of certain equity investee DD&A.

\(^{(b)}\) Natural Gas Midstream sensitivity incorporates current hedges, assumes same directional move in oil and gas prices, ethane rejection, no change in ethane frac spread, and assumes other NGL prices maintain same relationship with oil prices.
Segment Overview

The Markets that Actually Drive our Business

2016 Budgeted Segment EBDA = $8.0 billion

- 72% interstate pipelines
- 20% gathering, processing & treating
  - 87% fixed-fee
  - 13% other
- 8% intrastate pipelines & storage
- 60% refined products
- 40% crude / liquids
- 76% liquids
- 24% bulk
- 34% CO2 transport and sales
- 66% oil production-related
  - Production hedged:

<table>
<thead>
<tr>
<th>Year</th>
<th>Hedged</th>
<th>Avg. Px</th>
<th>Hedged</th>
<th>Avg. Px</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016</td>
<td>70%</td>
<td>$69</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td>54%</td>
<td>$73</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td>39%</td>
<td>$75</td>
<td></td>
<td></td>
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<tr>
<td>2019</td>
<td>21%</td>
<td>$65</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2020</td>
<td>-</td>
<td>-</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- 100% petroleum pipelines

(a) 2016 budgeted segment earnings before DD&A including proportionate amount of JV DD&A and excluding certain items.
(b) Approximately 87% of gathering, processing and treating business is derived from fixed-fee contracts. Approximately 30% of that is take-or-pay.
(c) Percentages based on currently hedged crude oil volumes as of 12/31/2015 relative to crude oil and heavy NGL (C4+) net equity production projected for 2016, and the Netherland Sewell reserve report plus management-approved Tall Cotton project barrels for 2017-2020.
KMI’s High Quality Cash Flow

Not all “fee-based” cash flow is created equal

2016 Budgeted Segment EBDA = $8.0 billion

- 3% Commodity-based Cash Flow
  - $0.3

- 6% Hedged Cash Flow
  - $0.5

- 24% Fee-based Cash Flow
  - $1.9

- 67% Take-or-pay Cash Flow
  - $5.3

91% Fee-based Cash Flow

Composition of 91% Fee-based Cash Flow

- 74% Take-or-pay Cash Flow
- 11% Other Fee-based Cash Flow
- 5% CO₂ S&T / Other Terminals
- 9% Products Pipelines

- 74% of fee-based cash flow secured by take-or-pay contracts
- Other fee-based cash flow supported by stable volumes / fee-based contracts / critical infrastructure between major supply hubs and stable end-user demand
  - Natural Gas Pipelines: G&P cash flow protected by dedicated producers and economically viable acreage
  - Products Pipelines: refined product volumes within ~1% of budget over past 6 years
  - Terminals: ~2/3 of Terminals’ Other Fee-based associated with high-utilization liquids assets and requirements contracts for petcoke and steel

(a) Based on 2016 budgeted Segment EBDA including JV DD&A.
Natural Gas Transportation & Storage
57% of 2016 Budgeted Total Segment EBDA

Natural gas transport & storage is KMI’s largest business

- U.S. natural gas demand expected to rise 27% through 2020\(^{(a)}\)
- KM moves about 38% of natural gas consumed in the U.S.
- **Transportation demand drivers:** power demand, exports (Mexico and LNG) and industrial market
  - 8.5 Bcf/d of new and pending contracts secured over past ~2 years (11% of estimated 2015 total U.S. demand)
- **Storage demand drivers:** power and LNG export demand variability (U.S. as swing LNG provider to world market)
  - KM the largest storage operator in the U.S. with 672 Bcf out of 4.0 Tcf market (17%)
  - Well-positioned to serve the variable-load requirements of LNG exports and power generation
  - Current increased contracting activity at improved rates in the Interstate and Intrastate markets
- **Gathering & processing trends:**
  - New LPG export capacity (docks and fleet) and Gulf Coast petrochemical demand
  - Meaningful upside if market returns to normal levels

### U.S. Natural Gas Supply & Demand\(^{(a)}\) (Bcf/d)

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
<th>Increase 5-yr</th>
<th>10-yr</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Demand</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LNG net exports</td>
<td>-0.1</td>
<td>7.8</td>
<td>10.8</td>
<td>7.9</td>
<td>10.9</td>
</tr>
<tr>
<td>Mexican net exports</td>
<td>2.9</td>
<td>5.2</td>
<td>6.5</td>
<td>2.3</td>
<td>3.6</td>
</tr>
<tr>
<td>Power</td>
<td>26.2</td>
<td>30.5</td>
<td>29.8</td>
<td>4.2</td>
<td>3.6</td>
</tr>
<tr>
<td>Industrial</td>
<td>20.7</td>
<td>24.3</td>
<td>25.8</td>
<td>3.6</td>
<td>5.0</td>
</tr>
<tr>
<td>Other</td>
<td>29.0</td>
<td>31.8</td>
<td>34.1</td>
<td>2.9</td>
<td>5.1</td>
</tr>
<tr>
<td>Total U.S. demand</td>
<td>78.7</td>
<td>99.6</td>
<td>107.0</td>
<td>20.9</td>
<td>28.3</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Supply</strong></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Marcellus / Utica</td>
<td>18.9</td>
<td>39.6</td>
<td>45.5</td>
<td>20.7</td>
<td>26.6</td>
</tr>
<tr>
<td>All other</td>
<td>59.8</td>
<td>60.0</td>
<td>61.5</td>
<td>0.2</td>
<td>1.7</td>
</tr>
<tr>
<td>Total U.S. supply</td>
<td>78.7</td>
<td>99.6</td>
<td>107.0</td>
<td>20.9</td>
<td>28.3</td>
</tr>
</tbody>
</table>

### Historical: NGL/WTI Ratio\(^{(b)}\) and NGL Processing Spreads\(^{(c)}\)

<table>
<thead>
<tr>
<th></th>
<th>NGL/WTI Ratio(^{(b)})</th>
<th>NGL Processing Spreads(^{(c)})</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Weighted Avg.</td>
<td>Ethane</td>
</tr>
<tr>
<td>2007-2012 Average</td>
<td>58%</td>
<td>$0.22</td>
</tr>
<tr>
<td>2013-2015 Average</td>
<td>41%</td>
<td>($0.10)</td>
</tr>
</tbody>
</table>

\(^{(a)}\) Source: Wood Mackenzie Fall 2015 Long-Term View.
\(^{(b)}\) NGL mix is 37% ethane, 32% propane, 11% normal butane, 6% isobutane, 14% natural gasoline.
\(^{(c)}\) Represents $/gal, assumes $0.10/gal T&F fee.
Liquids Transportation, Storage & Handling

33% of 2016 Budgeted Total Segment EBDA\(^{(a)}\)

**Strong Fundamentals & Demand Drivers**

- **Stable refined products demand**: vital pipeline network connecting refinery / port hubs to stable / growing demand markets
  - Refined product volumes within ~1% of budget over past 5 years
- **Petchem demand growth**: abundant, affordable domestic natural gas supply driving U.S. industrial and petrochemical renaissance
  - 261 announced U.S. projects representing cumulative investment of $158 billion from 2010 to 2023\(^{(b)}\)
  - UTOPIA pipeline provides needed takeaway capacity for Utica NGLs; backstopped by long-term take-or-pay contract (planned in-svc. Jan-2018)
- **Insufficient Oilsands takeaway capacity**: production expected to exceed takeaway capacity in 2017\(^{(c)}\)
  - KM terminaling and crude-by-rail logistics serve critical role, have significant presence in Edmonton
  - TMEP pipeline provides critical Westcoast tidewater access for crude oil; backstopped by long-term take-or-pay contracts (planned in-svc. 3Q 2019)
- **World-leading Footprint in Houston Ship Channel**: 1) Point of origin for 10 refineries, 2) Close proximity to growing industrial / petchem complex, 3) access to Eagle Ford light crude inputs
  - KM footprint on HSC provides unparalleled market access and connectivity: 43 MMBbls liquids capacity, best-in-class access to dock space, rail, pipeline
- **Permian pipelines are key intra-region supply**: Wink the only crude pipeline to serve El Paso refinery, Cortez the primary source of CO\(_2\) for enhanced oil recovery

\(^{(a)}\) Includes refined product, NGL, crude oil, CO\(_2\), and condensate pipelines; and liquids terminals; Liquids Businesses composition per 2016 budget.

\(^{(b)}\) American Chemistry Council, Year-end 2015 Chemical Industry Situation and Outlook; American Chemistry Accelerating Growth, December 2015.

\(^{(c)}\) Canadian Association of Petroleum Producers, Crude Oil Forecast, Markets & Transportation, June 2015, and Kinder Morgan analysis.
KMI Counterparty Exposure

Strong Customer Credit Profiles Limit KMI’s Risk \(^{(a)}\)

---

**High-Quality, Diversified Customer Base**

- Estimate approximately 2/3 of revenue \(^{(b)}\) generated by end-users (utilities, LDCs, refineries, chemical, large integrateds, etc.)
- KMI’s average customer represents less than 0.10% of annual revenue \(^{(b)}\)
- Top 25 customers represent ~44% of KMI’s revenue \(^{(b)}\)
- Top 209 customers \(^{(c)}\) represent ~83% of KMI’s revenue \(^{(b)}\)
  - ~5% of these revenues come from customers with a B- or lower rating, reflecting recent downgrade actions by S&P / Moody’s (of which, our expected net exposure is approximately half \(^{(d)}\))

---

**Top 25 Customers \(^{(b)}\)**

- A- Rated or Better 43%
- BBB Rated or Substantial Credit Support 43%
- BB+ to BB 10%
- B+ or below 4%

**Top 209 Customers \(^{(b,c)}\)**

- A- Rated or Better 34%
- BBB Rated or Substantial Credit Support 41%
- BB+ to B 12%
- B- or below 5%
- Not Rated 8%

---

(b) Based on budgeted 2016 net revenues of $11.5 billion, which includes 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 2016 budgeted revenue.
(d) Net exposure is revenues less credit support less market value of capacity.
5-year Growth Capex Program\(^{(a)}\)

~$18.2B of Attractive, Fee-based Projects

- World class asset footprint has helped secure growth projects with attractive returns, secured by long-term, fee-based contracts with creditworthy counterparties
  - ~90% of backlog is for fee-based pipelines, terminals and associated facilities
  - ~$2.2 billion of incremental EBITDA expected to be generated from growth capex program, excluding CO\(_2\)\(^{(b)}\)
  - Target at least 15% unlevered after-tax return to fund CO\(_2\) projects

- Due to current challenging capital markets, we are focused on further high-grading these investment opportunities

<table>
<thead>
<tr>
<th>Segment</th>
<th>Growth Projects(^{(a)}) ($B)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas Pipelines</td>
<td>$7.6</td>
</tr>
<tr>
<td>Products Pipelines</td>
<td>1.1</td>
</tr>
<tr>
<td>Terminals</td>
<td>2.3</td>
</tr>
<tr>
<td>CO(_2) – S&amp;T(^{(c)})</td>
<td>0.6</td>
</tr>
<tr>
<td>CO(_2) – EOR(^{(c)})</td>
<td>1.2</td>
</tr>
<tr>
<td>KM Canada</td>
<td>5.4</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$18.2</strong></td>
</tr>
</tbody>
</table>

\(\text{Segment Growth Projects}\) ~\$2.2 billion excluding CO\(_2\)\(^{(b)}\)
- ~7.5x multiple\(^{(d)}\)
- Target 15% minimum after-tax return for CO\(_2\)

---

(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 $835 million.
(b) Estimated first full-year EBITDA generated from fee-based pipelines, terminals and associated facilities. Excludes EBITDA from CO\(_2\) projects. Includes roughly $175 million of EBITDA contribution in 2016 budget.
(c) S&T = CO\(_2\) Source & Transportation. EOR = Enhanced Oil Recovery.
(d) Investment multiple calculated as total project cost divided by first full-year expected EBITDA.
Business Risks

- **Regulatory**
  - Products Pipeline FERC rate cases
  - Natural Gas FERC rate cases
  - Legislative and regulatory changes

- **CO₂ crude oil production volumes**

- **Throughput on our volume-based assets**

- **Counterparty credit**

- **Commodity prices**
  - 2016 budget price assumptions: $38/Bbl for crude, and $2.50/MMBtu for natural gas
  - Price sensitivities (full-year):
    - ~$6.5 million DCF per $1/Bbl change in crude price
    - ~$0.6 million DCF per $0.10/MMBtu change in natural gas price\(^{(a)}\)
    - ~$2.0 million DCF per 1% change in NGL / crude ratio

- **Project cost overruns / in-service delays**

- **Economically sensitive businesses (e.g., steel terminals)**

- **Foreign exchange rates**
  - 2016 budget rate assumption of 0.72 CAD / USD
  - Price sensitivity (full-year): ~$3 million DCF per 0.01 ratio change

- **Environmental (e.g., pipeline / asset failures)**

- **Terrorism**

- **Interest rates**
  - Full-year impact of 100-bp increase in floating rates equates to a pre-tax ~$99 million increase in interest expense\(^{(b)}\)

---

\(^{(a)}\) Natural Gas Midstream sensitivity incorporates current hedges, assumes same directional move in oil and gas prices, ethane rejection, no change in ethane frac spread, and assumes other NGL prices maintain same relationship with oil prices.

\(^{(b)}\) As of 12/31/2015 approximately $9.9 billion of KMI's net debt was floating rate (approximately 25% floating).
KMI: Attractive Value Proposition

- Unparalleled asset footprint
- Diversified energy infrastructure platform with stable, fee-based cash flow
- Industry leader in all business segments
- Focus on strong balance sheet and enhanced credit profile
- Highly visible, attractive growth opportunities
- Established track record
- Experienced management team aligned with investors
- Transparency to investors
- Investor-friendly, simple corporate structure
## Energy Toll Road
### Security of Cash

<table>
<thead>
<tr>
<th>Natural Gas Pipelines</th>
<th>Products Pipelines</th>
<th>Terminals</th>
<th>CO₂</th>
<th>Kinder Morgan Canada</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Volume Security</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interstate &amp; LNG: take or pay</td>
<td>Refined products: primarily volume-based</td>
<td>Liquids &amp; Jones Act: primarily take or pay</td>
<td>S&amp;T: primarily minimum volume guarantee</td>
<td>Essentially no volume risk</td>
</tr>
<tr>
<td>Intra: ~73% take or pay</td>
<td>Crude / liquids: take or pay</td>
<td>Bulk: primarily minimum volume guarantee, or requirements</td>
<td>O&amp;G: volume-based</td>
<td></td>
</tr>
<tr>
<td>G&amp;P: ~87% fee-based with minimum volume requirements / acreage dedications</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Average Remaining Contract Life</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interstate: 6.3 yrs.</td>
<td>Refined products: generally not applicable</td>
<td>Liquids: 3.8 yrs.</td>
<td>S&amp;T: 9.0 yrs.</td>
<td>1.0 yr. (c)</td>
</tr>
<tr>
<td>LNG: 16.4 yrs.</td>
<td>Crude / liquids: 5.8 yrs.</td>
<td>Jones Act: 3.6 yrs. (b)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Intra: 4.8 yrs. (a)</td>
<td></td>
<td>Bulk: 3.7 yrs.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>G&amp;P: 5.0 yrs.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Pricing Security</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interstate: primarily fixed based on contract</td>
<td>Refined products: annual FERC tariff escalator (PPI + 1.23%)</td>
<td>Based on contract; typically fixed or tied to PPI</td>
<td>S&amp;T: 82% protected by minimum volumes and floors (d)</td>
<td>Fixed based on toll settlement</td>
</tr>
<tr>
<td>Intra: primarily fixed margin</td>
<td>Crude / liquids: primarily fixed based on contract</td>
<td></td>
<td>O&amp;G: volumes 70% hedged (e)</td>
<td></td>
</tr>
<tr>
<td>G&amp;P: primarily fixed price</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Regulatory Security</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interstate: regulated return</td>
<td>Pipelines: regulated return</td>
<td>Not price regulated</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Intra: essentially market-based</td>
<td>Terminals &amp; transmix: not price regulated (f)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>G&amp;P: market-based</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Commodity Price Exposure</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interstate: no direct exposure</td>
<td>Minimal, limited to transmix business</td>
<td>No direct exposure</td>
<td>Full-yr 2016: $4.8MM in DCF per $1/Bbl change in oil price</td>
<td>No direct exposure</td>
</tr>
<tr>
<td>Intra: limited exposure</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>G&amp;P: limited exposure</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

---

All figures as of 1/1/2016.

(a) Transportation for intrastate pipelines includes term purchase and sale portfolio.

(b) Jones Act vessels: average remaining contract term for operating tankers (8) and tankers under construction (6) is 3.6 years, or 5.8 years including options to extend.

(c) Existing 2013-2015 toll settlement to be extended to coincide with in-service of Trans Mountain expansion.

(d) Based on 2016 budget.

(e) Percent of 2016 budgeted net crude oil and heavier natural gas liquids (C4+) production.

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

Liquids Pipeline Right-of-way

Liquids Pipelines
Incidents per 1,000 Miles

<table>
<thead>
<tr>
<th>Year</th>
<th>Incidents</th>
<th>KM Incidents</th>
<th>Industry 3-yr Avg</th>
<th>Industry 2011 Avg</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>0.45</td>
<td>0.29</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>2007</td>
<td>0.29</td>
<td>0.32</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>2008</td>
<td>0.21</td>
<td>0.08</td>
<td>0.08</td>
<td>0.08</td>
</tr>
<tr>
<td>2009</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>2010</td>
<td>0.08</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>2011</td>
<td>0.08</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>2012</td>
<td>0.24</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>2013</td>
<td>0.57</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>2014</td>
<td>0.33</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>2015</td>
<td>0.16</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>LTM 1/31/16</td>
<td>0.20</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
</tr>
</tbody>
</table>

Liquids Pipelines
Release Rate

<table>
<thead>
<tr>
<th>Year</th>
<th>Rate</th>
<th>KM Incidents</th>
<th>Industry 3-yr Avg</th>
<th>Industry 2011 Avg</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>6.00</td>
<td>6.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>2007</td>
<td>15.50</td>
<td>15.50</td>
<td>0.00</td>
<td>0.00</td>
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<tr>
<td>2008</td>
<td>2.50</td>
<td>2.50</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>2009</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>2010</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>2011</td>
<td>13.05</td>
<td>13.05</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>2012</td>
<td>0.11</td>
<td>0.11</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>2013</td>
<td>0.67</td>
<td>0.67</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>2014</td>
<td>17.96</td>
<td>17.96</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>2015</td>
<td>10.94</td>
<td>10.94</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>LTM 1/31/16</td>
<td>0.04</td>
<td>0.04</td>
<td>0.01</td>
<td>0.01</td>
</tr>
</tbody>
</table>

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:

1. Explosion or fire not intentionally set by the operator.
2. Release 5 barrels or greater. (NOTE: PHMSA does not record system location for releases less than 5 barrels)
3. Death of any person.
4. Personal injury necessitating hospitalization.
5. 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) 2012–2014 most recent PHMSA 3-yr average available.
Incidents & Releases
Natural Gas Pipeline Right-of-way

(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:

1. 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.

2. An event that results in an emergency shutdown of an LNG facility.

3. 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) 2012–2014 most recent PHMSA 3-yr average available.

(c) Rupture defined as a break, burst, or failure that exposes a visible pipeline fracture surface.


2. 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\(^{(a)}\)

**(a)** 12-month safety performance summary as of 1/31/2016.

**(b)** Industry average not available for Terminals.
Natural Gas Pipelines
Segment Outlook

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

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

**Project Backlog:**
- $7.6 billion of identified growth projects\(^{(a)}\)
  - TGP Northeast market-area expansion (NED)
  - LNG liquefaction (Elba Island)
  - Transport projects supporting LNG liquefaction
  - TGP north-to-south projects
  - SNG / Elba Express expansions
  - Expansions to Mexico border

---

\(^{(a)}\) Excludes acquisitions, includes KM share of non-wholly owned projects. Includes projects currently under construction.
Contracted Capacity and Term by Region

<table>
<thead>
<tr>
<th>Region</th>
<th>Service</th>
<th>Capacity</th>
<th>Avg. Term Remaining</th>
</tr>
</thead>
<tbody>
<tr>
<td>North</td>
<td>Storage</td>
<td>356 Bcf</td>
<td>3 yrs., 7 mos.</td>
</tr>
<tr>
<td></td>
<td>Transport</td>
<td>19.1 Bcf/d</td>
<td>5 yrs., 7 mos.</td>
</tr>
<tr>
<td>South</td>
<td>Storage</td>
<td>52 Bcf</td>
<td>1 yrs., 10 mos.</td>
</tr>
<tr>
<td></td>
<td>Transport</td>
<td>13.0 Bcf/d</td>
<td>7 yrs., 11 mos.</td>
</tr>
<tr>
<td></td>
<td>LNG</td>
<td>18 Bcf</td>
<td>16 yrs., 5 mos.</td>
</tr>
<tr>
<td>West</td>
<td>Storage</td>
<td>45 Bcf</td>
<td>6 yrs., 3 mos.</td>
</tr>
<tr>
<td></td>
<td>Transport</td>
<td>17.9 Bcf/d</td>
<td>5 yrs., 11 mos.</td>
</tr>
<tr>
<td>Midstream</td>
<td>Purchases</td>
<td>2.6 Bcf/d</td>
<td>2 yrs., 1 mos.</td>
</tr>
<tr>
<td></td>
<td>Sales</td>
<td>3.3 Bcf/d</td>
<td>2 yrs., 6 mos.</td>
</tr>
<tr>
<td></td>
<td>Storage</td>
<td>93 Bcf</td>
<td>4 yrs., 2 mos.</td>
</tr>
<tr>
<td></td>
<td>Transport</td>
<td>3.3 Bcf/d</td>
<td>4 yrs., 4 mos.</td>
</tr>
<tr>
<td></td>
<td>Processing</td>
<td>1.6 Bcf/d</td>
<td>5 yrs., 9 mos.</td>
</tr>
</tbody>
</table>

- **Net annual incremental re-contracting exposure (KM share)\(^{(a)}\):**
  (% of $8.0 billion Total KMI Segment EBDA)

<table>
<thead>
<tr>
<th>Region</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>North</td>
<td>0.0%</td>
<td>(0.9%)</td>
</tr>
<tr>
<td>South</td>
<td>(0.1%)</td>
<td>(0.2%)</td>
</tr>
<tr>
<td>West</td>
<td>(0.5%)</td>
<td>(0.1%)</td>
</tr>
<tr>
<td>Midstream</td>
<td>(0.1%)</td>
<td>(0.1%)</td>
</tr>
<tr>
<td>Total Nat. Gas Segment</td>
<td>(0.7%)</td>
<td>(1.3%)</td>
</tr>
</tbody>
</table>

\(^{(a)}\) Negative figures represent unfavorable re-contracting exposure. Includes transportation and storage contracts.
Products Pipelines
Segment Outlook

Opportunities for growth from increased liquids production

Long-term Growth Drivers:
- Increased demand for refined product volumes
- Development of shale play liquids transportation and processing (e.g. UTOPIA and KMCC / splitter)
- Tuck-in acquisitions
- Extension of refined products pipeline system into Southeast U.S. (e.g. Palmetto Pipeline)
- Repurposing portions of existing footprint in different product uses

Project Backlog:
- $1.1 billion of identified growth projects over next two years\(^{(a)}\), including:
  - UTOPIA
  - Palmetto

(a) Excludes acquisitions, includes KM share of non-wholly owned projects. Includes projects currently under construction.
**Historical Demand and 2016 EIA Outlook**

### U.S. Refined Product Consumption

<table>
<thead>
<tr>
<th>Year</th>
<th>Motor</th>
<th>Gasoline</th>
<th>Distillate Fuel Oil</th>
<th>Jet Fuel</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>8.99</td>
<td>9.00</td>
<td>3.50</td>
<td>1.54</td>
</tr>
<tr>
<td>2009</td>
<td>8.99</td>
<td>8.90</td>
<td>3.22</td>
<td>1.39</td>
</tr>
<tr>
<td>2010</td>
<td>8.75</td>
<td>8.75</td>
<td>3.43</td>
<td>1.43</td>
</tr>
<tr>
<td>2011</td>
<td>8.68</td>
<td>8.68</td>
<td>3.90</td>
<td>1.43</td>
</tr>
<tr>
<td>2012</td>
<td>8.84</td>
<td>8.84</td>
<td>3.74</td>
<td>1.43</td>
</tr>
<tr>
<td>2013</td>
<td>8.92</td>
<td>8.92</td>
<td>3.83</td>
<td>1.43</td>
</tr>
<tr>
<td>2014</td>
<td>9.16</td>
<td>9.16</td>
<td>3.96</td>
<td>1.47</td>
</tr>
<tr>
<td>2015</td>
<td>9.23</td>
<td>9.23</td>
<td>4.03</td>
<td>1.54</td>
</tr>
<tr>
<td>2016E</td>
<td></td>
<td></td>
<td></td>
<td>1.53</td>
</tr>
</tbody>
</table>

### U.S. Refined Product Demand Outlook

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
<th>2016E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mogas</td>
<td>0.9%</td>
<td>2.6%</td>
<td>1.1%</td>
</tr>
<tr>
<td>Distillate</td>
<td>5.5%</td>
<td>-1.9%</td>
<td>2.1%</td>
</tr>
<tr>
<td>Jet Fuel</td>
<td>2.5%</td>
<td>4.8%</td>
<td>-0.5%</td>
</tr>
<tr>
<td>Total – EIA</td>
<td>2.3%</td>
<td>1.6%</td>
<td>1.2%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
<th>2016E</th>
</tr>
</thead>
<tbody>
<tr>
<td>KM</td>
<td>3.5%</td>
<td>3.1%</td>
<td>1.9%</td>
</tr>
</tbody>
</table>

### FERC Tariff Index

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>FERC Rate Increase</td>
<td>3.89%</td>
<td>4.58%</td>
<td>-1.97%</td>
</tr>
</tbody>
</table>

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(a) Source: EIA Table 4a. U.S. Crude Oil and Liquid Fuel Supply, Consumption, and Inventories and Figure 15 U.S. Liquids Fuel Consumption Growth – January 2016
(b) Expected rate decrease based on current regulatory information, based on PPI FG +1.23%.
Terminals
Segment Outlook

Well-located in refinery / port hubs and inland waterways

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:
- $2.3 billion of identified growth projects over the next five years, including:
  - Jones Act tanker builds
  - Edmonton merchant crude terminal
  - Houston Ship Channel network expansion
  - Chemical terminal development

KM Terminal Facilities:

<table>
<thead>
<tr>
<th>Type</th>
<th>Terminals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk</td>
<td>59</td>
</tr>
<tr>
<td>Liquids</td>
<td>52</td>
</tr>
<tr>
<td>Total KMT</td>
<td>111</td>
</tr>
<tr>
<td>KMPP</td>
<td>69 Liquid Terminals</td>
</tr>
<tr>
<td>Total KM</td>
<td>180 Terminals</td>
</tr>
</tbody>
</table>

8 Jones Act Tankers

* Includes KM / BP JV Terminals

(a) Excludes acquisitions, includes KM share of non-wholly owned projects. Includes projects currently under construction.
Terminals Segment
76% of 2016 Budgeted Segment EBDA Based on Liquids Business

Terminals 2016 Budgeted EBDA

Liquids Revenue\(^{(a)}\)
- 79% of liquids revenues secured by take-or-pay contracts
  - Fixed monthly advanced lease payments for use of our assets
  - Monthly Warehousing Charge (MWC) tank capacity leases
  - Minimum throughput-based contracts
  - Marine charters
- 20% fee-based
  - Ancillary fees: blending, additives and docks
  - Throughput fees: supported by local market demand
- 19% supported by requirements contracts
  - Tied to either petroleum coke manufacture or steel production
- 43% fee-based
  - Volumetric per ton fees and ancillary services

Bulk Revenue\(^{(a)}\)
- 38% of revenues supported by Take-or-Pay contracts
  - Minimum throughput commitments
- 19% supported by requirements contracts
  - Tied to either petroleum coke manufacture or steel production
- 43% fee-based
  - Volumetric per ton fees and ancillary services

\(^{(a)}\) Per 2016 budget.
Houston Ship Channel

**Market:** World’s largest integrated refined product terminaling system

**Infrastructure:** 43 million barrels of capacity connected to 10 refineries

**Customers:** Refiners, integrated majors, international traders, chemical producers, wholesale marketers

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**Fee-based revenues tied to tank leases**
- Tank capacity under current lease: 100%
- Average remaining contract lease: 3.5 years\(^{(a)}\)
- Top 5 customers: 36%\(^{(b)}\)
- Top 10 customers: 53%\(^{(b)}\)

**Irreducible integrated assets**
- 20 inbound pipelines, 15 outbound pipelines
- 14 cross-channel pipelines
- 12 barge docks
- 11 ship docks
- 9-bay truck rack (90 MBbl/d avg.)
- Unit train facilities (crude, condensate, ethanol)

\(\) As of 1/1/2016 for petroleum liquids.
\(\) Based on 2016 budgeted revenues.
**CO₂ Segment Outlook**

**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, including KM operated fields

**Project Backlog:**
- Identified growth projects totaling $0.6 billion and $1.2 billion in S&T and EOR, respectively, over next five years\(^{(b)}\), including:
  - S&T: Southwest Colorado CO₂ production
  - EOR: SACROC / Yates / Katz / Goldsmith / Tall Cotton

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

\( (b) \) Excludes acquisitions, includes KM share of non-wholly owned projects. Includes projects currently under construction.
Kinder Morgan Canada

Segment Outlook

**Long-term Growth Drivers:**
- Expand Oilsands export capacity to West Coast and Asia
  - Following successful open season, 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 3Q 2019
- Expanded dock capabilities (Vancouver)
  - TMEP will increase dock capacity to over 600 MBbl/d
  - Access to global markets

**Project Backlog:**
- USD $5.4 billion expansion of TMEP
2016 Budgeted Growth Capital

(millions)

<table>
<thead>
<tr>
<th>Growth capital(a)</th>
<th>2016 Budget</th>
<th>2015 Actual</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas Pipelines</td>
<td>$1,565</td>
<td>$1,528</td>
</tr>
<tr>
<td>CO₂ - S&amp;T</td>
<td>9</td>
<td>163</td>
</tr>
<tr>
<td>CO₂ - EOR</td>
<td>213</td>
<td>449</td>
</tr>
<tr>
<td>Products Pipelines</td>
<td>344</td>
<td>431</td>
</tr>
<tr>
<td>Terminals</td>
<td>935</td>
<td>854</td>
</tr>
<tr>
<td>Kinder Morgan Canada</td>
<td>215</td>
<td>105</td>
</tr>
<tr>
<td>Corporate/Other</td>
<td>-</td>
<td>2</td>
</tr>
<tr>
<td>Subtotal - growth capital excl. large acquisitions(a)</td>
<td>3,281</td>
<td>3,532</td>
</tr>
<tr>
<td>Hiland Midstream</td>
<td>-</td>
<td>3,058</td>
</tr>
<tr>
<td><strong>Total growth capital</strong></td>
<td>$3,281</td>
<td>$6,590</td>
</tr>
</tbody>
</table>

2016 budgeted growth capital fully funded by operating cash flow, no requirement to access capital markets

(a) Includes JV Contributions of $284 and $125 million, small acquisitions of $380 and $358 million (net of divestitures and proceeds from new JVs) and inclusion capital of $23MM and $19MM, for 2016 and 2015, respectively.
Credit Ratios and Liquidity\(^{(a)}\)

\(\text{(\$ in millions)}\)

<table>
<thead>
<tr>
<th>Leverage metrics</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016 Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net debt(^{(b)}) to EBITDA</td>
<td>5.4x</td>
<td>5.0x</td>
<td>5.5x</td>
<td>5.6x</td>
<td>5.5x</td>
</tr>
<tr>
<td>EBITDA to interest</td>
<td>4.0x</td>
<td>3.9x</td>
<td>4.1x</td>
<td>3.5x</td>
<td>3.6x</td>
</tr>
</tbody>
</table>

**Revolver capacity\(^{(c)}\)**

<table>
<thead>
<tr>
<th>Committed revolving credit facility</th>
<th>$ 4,000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less:</td>
<td></td>
</tr>
<tr>
<td>CP / Revolver borrowing</td>
<td>-</td>
</tr>
<tr>
<td>Letters of credit</td>
<td>(115)</td>
</tr>
<tr>
<td><strong>Excess capacity</strong></td>
<td><strong>$ 3,885</strong></td>
</tr>
</tbody>
</table>

**Long-term debt maturities\(^{(d)}\)**

<table>
<thead>
<tr>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>$ 1,667</td>
<td>3,059</td>
<td>2,327</td>
<td>3,817</td>
<td>2,932</td>
</tr>
</tbody>
</table>

Note: As of 12/31/2015. Excludes certain items.

(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 increased to $5 billion on 1/26/2016 (maturity in November 2019).
(d) 5-year maturity schedule of annual aggregate long-term debt principal. Excludes corporate revolver and $1 billion term loan maturing 2019.