KINDER MORGAN, INC.
Form 10-K
February 10, 2017
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2016
or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____to_____
Commission file number: 001-35081
Kinder Morgan, Inc.
(Exact name of registrant as specified in its charter)

Delaware	80-0682103
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1001 Louisiana Street, Suite 1000, Houston, Texas 77002
(Address of principal executive offices) (zip code)

Registrant's telephone number, including area code: 713-369-9000

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Class P Common Stock	New York Stock Exchange
Warrants to Purchase Class P Common Stock	New York Stock Exchange
Depositary Shares, each representing a 1/20th interest in a share of 9.75% Series A Mandatory Convertible Preferred Stock	New York Stock Exchange
1.500% Senior Notes due 2022	New York Stock Exchange
2.250% Senior Notes due 2027	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934. Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K(§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).
Large accelerated filer þ Accelerated filer o Non-accelerated filer o Smaller reporting company o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes o No þ
Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on closing prices in the daily composite list for transactions on the New York Stock Exchange on June 30, 2016 was approximately $36,035,868,866. As of February 9, 2017, the registrant had 2,232,438,943 Class P shares outstanding.

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KINDER MORGAN, INC. AND SUBSIDIARIES
GLOSSARY

Company Abbreviations

Calnev	=	Calnev Pipe Line LLC
CIG	=	Colorado Interstate Gas Company, L.L.C.
Copano	=	Copano Energy, L.L.C.
CPG	=	Cheyenne Plains Gas Pipeline Company, L.L.C.
EagleHawk	=	EagleHawk Field Services LLC
Elba Express	=	Elba Express Company, L.L.C.
ELC	=	Elba Liquefaction Company, L.L.C.
EP	=	El Paso Corporation and its majority-owned and controlled subsidiaries
EPB	=	El Paso Pipeline Partners, L.P. and its majority-owned and controlled subsidiaries
EPNG	=	El Paso Natural Gas Company, L.L.C.
EPPOC	=	El Paso Pipeline Partners Operating Company, L.L.C.
FEP	=	Fayetteville Express Pipeline LLC
Hiland	=	Hiland Partners, LP
KinderHawk	=	KinderHawk Field Services LLC
$KMCO_2$	=	Kinder Morgan CO_2 Company, L.P.
KMEP	=	Kinder Morgan Energy Partners, L.P.
KMGP	=	Kinder Morgan G.P., Inc.
KMI	=	Kinder Morgan Inc. and its majority-owned and/or controlled subsidiaries
KMLP	=	Kinder Morgan Louisiana Pipeline LLC
KMP	=	Kinder Morgan Energy Partners, L.P. and its majority-owned and controlled subsidiaries
KMR	=	Kinder Morgan Management, LLC
MEP	=	Midcontinent Express Pipeline LLC
NGPL	=	Natural Gas Pipeline Company of America LLC
Ruby	=	Ruby Pipeline Holding Company, L.L.C.
SFPP	=	SFPP, L.P.
SLNG	=	Southern LNG Company, L.L.C.
SNG	=	Southern Natural Gas Company, L.L.C.
TGP	=	Tennessee Gas Pipeline Company, L.L.C.
WIC	=	Wyoming Interstate Company, L.L.C.
WYCO	=	WYCO Development L.L.C.

Unless the context otherwise requires, references to “we,” “us,” “our,” or “the Company” are intended to mean Kinder Morgan Inc. and its majority-owned and/or controlled subsidiaries.

Common Industry and Other Terms

/d	=	per day
AFUDC	=	allowance for funds used during construction
BBtu	=	billion British Thermal Units
Bcf	=	billion cubic feet
CERCLA	=	Comprehensive Environmental Response, Compensation and Liability Act
CO_2	=	carbon dioxide or our CO_2 business segment
CPUC	=	California Public Utilities Commission
DCF	=	distributable cash flow
DD&A	=	depreciation, depletion and amortization
DGCL	=	General Corporation Law of the state of Delaware
Dth	=	dekatherms
EBDA	=	earnings before depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments
EPA	=	
LIBOR	=	London Interbank Offered Rate
LLC	=	limited liability company
LNG	=	liquefied natural gas
MBbl	=	thousand barrels
MDth	=	thousand dekatherms
MLP	=	master limited partnership
MMBbl	=	million barrels
MMcf	=	million cubic feet
NEB	=	National Energy Board
NGL	=	natural gas liquids
NYMEX	=	New York Mercantile Exchange
NYSE	=	New York Stock Exchange
OTC	=	over-the-counter
PHMSA	=	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration

		United States Environmental Protection Agency			
FASB	=	Financial Accounting Standards Board	U.S.	=	United States of America
FERC	=	Federal Energy Regulatory Commission	SEC	=	United States Securities and Exchange Commission
FTC	=	Federal Trade Commission			
GAAP	=	United States Generally Accepted Accounting Principles	TBtu	=	trillion British Thermal Units
			WTI	=	West Texas Intermediate

When we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

Information Regarding Forward-Looking Statements

This report includes forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as “anticipate,” “believe,” “intend,” “plan,” “projection,” “forecast,” “strategy,” “outlook,” “continue,” “estimate,” “expect,” “may,” or the negative of those terms or other variations of them or comparable terminology. In particular, expressed or implied statements concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow, service debt or 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 may differ materially from those expressed in our forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or accurately predict. Specific factors that could cause actual results to differ from those in our forward-looking statements include:

- the extent of volatility in prices for and resulting changes in supply of and demand for NGL, refined petroleum products, oil, CO_2, natural gas, electricity, coal, steel and other bulk materials and chemicals and certain agricultural products in North America;

- economic activity, weather, alternative energy sources, conservation and technological advances that may affect price trends and demand;

- changes in our tariff rates required by the FERC, the CPUC, Canada’s NEB or another regulatory agency;

- our ability to acquire new businesses and assets and integrate those operations into our existing operations, and make cost-saving changes in operations, particularly if we undertake multiple acquisitions in a relatively short period of time, as well as our ability to expand our facilities;

- our ability to safely operate and maintain our existing assets and to access or construct new pipeline, gas processing, gas storage and NGL fractionation capacity;

- our ability to attract and retain key management and operations personnel;

- difficulties or delays experienced by railroads, barges, trucks, ships or pipelines in delivering products to or from our terminals or pipelines;

- shut-downs or cutbacks at major refineries, petrochemical or chemical plants, natural gas processing plants, ports, utilities, military bases or other businesses that use our services or provide services or products to us;

- changes in crude oil and natural gas production (and the NGL content of natural gas production) from exploration and production areas that we serve, such as the Permian Basin area of West Texas, the shale plays in North Dakota, Oklahoma, Ohio, Pennsylvania and Texas, and the U.S. Rocky Mountains and the Alberta, Canada oil sands;

- changes in laws or regulations, third-party relations and approvals, and decisions of courts, regulators and governmental bodies that may increase our compliance costs, restrict our ability to provide or reduce demand for our services, or otherwise adversely affect our business;

- interruptions of operations at our facilities due to natural disasters, damage by third-parties, power shortages, strikes, riots, terrorism (including cyber attacks), war or other causes;

- the uncertainty inherent in estimating future oil, natural gas, and CO_2 production or reserves that we may experience;

- regulatory, environmental, political, legal, operational and geological uncertainties that could affect our ability to complete our expansion projects on time and on budget;

- the timing and success of our business development efforts, including our ability to renew long-term customer contracts at economically attractive rates;

- the ability of our customers and other counterparties to perform under their contracts with us;

- competition from other pipelines or other forms of transportation;

- changes in accounting pronouncements that impact the measurement of our results of operations, the timing of when such measurements are to be made and recorded, and the disclosures surrounding these activities;

- changes in tax laws;

- our ability to access external sources of financing in sufficient amounts and on acceptable terms to the extent needed to fund acquisitions of operating businesses and assets and expansions of our facilities;

- our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at a competitive disadvantage compared to our competitors that have less debt, or have other adverse consequences;

- our ability to obtain insurance coverage without significant levels of self-retention of risk;

- acts of nature, sabotage, terrorism (including cyber attacks) or other similar acts or accidents causing damage to our properties greater than our insurance coverage limits;

- possible changes in our and our subsidiaries' credit ratings;

- conditions in the capital and credit markets, inflation and fluctuations in interest rates;

- political and economic instability of the oil producing nations of the world;

- national, international, regional and local economic, competitive and regulatory conditions and developments, including the effects of any enactment of import or export duties, tariffs or similar measures;

- our ability to achieve cost savings and revenue growth;

- foreign exchange fluctuations;

- the extent of our success in developing and producing CO_2 and oil and gas reserves, including the risks inherent in development drilling, well completion and other development activities;

- engineering and mechanical or technological difficulties that we may experience with operational equipment, in well completions and work-overs, and in drilling new wells; and

- unfavorable results of litigation and the outcome of contingencies referred to in Note 17 "Litigation, Environmental and Other Contingencies" to our consolidated financial statements.

The foregoing list should not be construed to be exhaustive. We believe the forward-looking statements in this report are reasonable. However, there is no assurance that any of the actions, events or results expressed in forward-looking statements will occur, or if any of them do, of their timing or what impact they will have on our results of operations or financial condition. Because of these uncertainties, you should not put undue reliance on any forward-looking statements.

Additional discussion of factors that may affect our forward-looking statements appears elsewhere in this report, including in Item 1A, "Risk Factors," Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk-Energy Commodity Market Risk." In addition, there is a general level of uncertainty regarding the extent to which potential positive or negative changes to fiscal, tax and trade policies may impact us and those with whom we do business. It is not possible at this time to predict the extent of any such impact. When considering forward-looking statements, you should keep in mind the factors described in this section and the other sections referenced above. These factors could cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation, other than as required by applicable law, and described below under Items 1 and 2, “Business and Properties–—(a) General Development of Business—Recent Developments—2017 Outlook,” to update the above list or to announce publicly the result of any revisions to any of our forward-looking statements to reflect future events or developments.

PART I

Items 1 and 2. Business and Properties.
We are one of the largest energy infrastructure companies in North America. We own an interest in or operate approximately 84,000 miles of pipelines and 155 terminals. Our pipelines transport natural gas, refined petroleum products, crude oil, condensate, CO_2 and other products, and our terminals transload and store petroleum products, ethanol and chemicals, and handle such products as steel, coal and petroleum coke. We are also a leading producer of CO_2, which we and others utilize for enhanced oil recovery projects primarily in the Permian basin. Our common stock trades on the NYSE under the symbol “KMI.”

(a) General Development of Business

Organizational Structure

We are a Delaware corporation and our common stock has been publicly traded since February 2011. Prior to November 2014, we conducted most of our business through two master limited partnerships: KMP (whose business and affairs were managed by KMR, a publicly traded limited liability company), and EPB.

On November 26, 2014, we completed our acquisition, pursuant to three separate merger agreements, of all of the outstanding common units of KMP and EPB and all of the outstanding shares of KMR that we did not already own. The transactions are referred to collectively as the “Merger Transactions.”

As we controlled each of KMP, KMR and EPB before and continued to control each of them after the Merger Transactions, the changes in our ownership interest in each of KMP, KMR and EPB were accounted for as an equity transaction and no gain or loss was recognized in our consolidated statements of income related to the Merger Transactions. After closing the Merger Transactions, KMR was merged with and into KMI.

Prior to the Merger Transactions, we owned an approximate 10% limited partner interest (including our interest in KMR) and the 2% general partner interest including incentive distribution rights in KMP, and an approximate 39% limited partner interest and the 2% general partner interest and incentive distribution rights in EPB. Effective with the Merger Transactions, the incentive distribution rights held by the general partner of KMP were eliminated.

The equity interests in KMP, EPB and KMR (which are all consolidated in our financial statements) owned by the public prior to the Merger Transactions are reflected within “Noncontrolling interests” in our accompanying consolidated statements of stockholders’ equity. The earnings recorded by KMP, EPB and KMR that were attributed to the units and shares, respectively, held by the public prior to the Merger Transactions are reported as “Net income attributable to noncontrolling interests” in our accompanying consolidated statement of income for the year ended December 31, 2014.

Additionally, on January 1, 2015, EPB and its subsidiary, EPPOC, merged with and into KMP. As a result of such merger, all of the subsidiaries of EPB and EPPOC became wholly owned subsidiaries of KMP. References to EPB refer to EPB for periods prior to its merger into KMP.

You should read the following in conjunction with our audited consolidated financial statements and the notes thereto. We have prepared our accompanying consolidated financial statements under GAAP and the rules and regulations of the SEC. Our accounting records are maintained in U.S. dollars and all references to dollars in this report are to U.S. dollars, except where stated otherwise. Our consolidated financial statements include our accounts and those of our majority-owned and/or controlled subsidiaries, and all significant intercompany items have been eliminated in consolidation. The address of our principal executive offices is 1001 Louisiana Street, Suite 1000, Houston, Texas 77002, and our telephone number at this address is (713) 369-9000.

Recent Developments

The following is a brief listing of significant developments and updates related to our major projects and other transactions. Additional information regarding most of these items may be found elsewhere in this report. “Capital Scope” is estimated for our share of the described project which may include portions not yet completed.

Asset or project	Description	Activity	Approx. Capital Scope
Placed in service, acquisitions or divestitures			
SNG natural gas pipeline system	Sold 50% interest in SNG natural gas pipeline system to The Southern Company and formed a joint venture, which includes our remaining 50% interest in SNG.	Completed in September 2016	n/a
KM and BP Joint Venture	Acquired 15 refined products terminals and associated infrastructure. KM and BP formed a joint venture, with an equity ownership interest of 75% and 25%, respectively, which owns 14 of the acquired assets. One terminal is owned solely by KM.	Acquired February 2016.	$349 million
Elba Express and SNG expansion	Expansion project that provides 854,000 Dth/d incremental contracted, firm natural gas transportation service supporting the needs of customers in Georgia, South Carolina and northern Florida, and also serving ELC. Supported by long-term contracts.	Initial service began in December 2016.	$285 million
Cow Canyon development	An expansion project that increases CO_2 production in the Cow Canyon area of the McElmo Dome source field by 200 MMcf/d.	Majority placed in service in 2015 and completed during the 1st quarter of 2016.	$229 million
TGP South System Flexibility	Expansion project that provides more than 900 miles of north-to-south transportation capacity of 500,000 Dth/d on our TGP system from Tennessee to South Texas and expands our transportation service to Mexico. Subscribed under long-term firm transportation contracts.	350,000 Dth/d placed into service during 2015. The final 150,000 Dth/d capacity increment was placed in service in October 2016.	$230 million
Cortez Pipeline expansion	Project will increase capacity from 1.35 Bcf/d to 1.5 Bcf/d on this existing pipeline. This pipeline will transport CO_2 from southwestern Colorado to eastern New Mexico and west Texas for use in enhanced oil recovery projects.	Placed in service November 2016.	$227 million
Other Announcements			
Natural Gas Pipelines			
ELC and SLNG expansion	Building of new natural gas liquefaction and export facilities at our SLNG natural gas terminal on Elba Island, near Savannah, Ga., with a total capacity of 2.5 million tonnes per year of LNG, equivalent to 350 MMcf/d of natural gas. Supported by a 20-year contract with Shell.	First of 10 liquefaction units expected in service in mid-2018 with the remainder by early 2019.	$1.9 billion
TGP Broad Run Expansion	Second of two separate projects modifying existing pipeline facilities to create 790,000 Dth/d of north-to-south gas transportation capacity from a receipt point in West Virginia to delivery points in Mississippi and Louisiana. Subscribed under long-term firm transportation contracts.	Broad Run Flexibility facilities (590,000 Dth/d) were placed in service November 2015. Broad Run Expansion (200,000 Dth/d) expected to be in service in June 2018.	$452 million
EPNG South Mainline Expansion (formerly upstream Sierrita)	Expansion projects to provide 471,000 Dth/d contracted, firm natural gas transport capacity with a first phase of system improvements to deliver volumes to the Sierrita pipeline and the second phase for incremental deliveries of	Phase one placed in service October 2014 ($2 million), phase two expected in service July	$135 million

	natural gas to Arizona and California.	2020 ($133 million).	
Texas Intrastate Crossover Expansion	Expansion project to provide transportation capacity from the Katy Hub, the company's Houston Central processing plant, and other third party receipt points to serve customers in Texas and Mexico. Phase I is supported by commitments of over 800,000 Dth/d, including contracts with Cheniere Energy, Inc. at its Corpus Christi LNG facility and Comisión Federal de Electricidad. Phase 2, which is supported by a long-term commitment from SK E&S LNG, LLC, will provide service to the Freeport LNG export facility and bring the total project capacity to over 1,000,000 Dth/d.	Phase 1 was placed in service in September 2016. Phase 2 is expected to be in service by third quarter 2019.	$307 million
TGP Southwest Louisiana Supply (formerly Cameron LNG)	Project provides 900,000 Dth/d of long-term capacity to the future Cameron LNG export complex at Hackberry, Louisiana. Subscribed under long-term firm transportation contracts.	Expected in service February 2018.	$179 million

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Asset or project	Description	Activity	Approx. Capital Scope
TGP Susquehanna West	Expansion project that provides 145,000 Dth/d incremental natural gas transportation capacity, serving the northeast Marcellus to points of liquidity. Subscribed under long-term firm transportation contracts.	Expected in service November 2017.	$156 million
KMLP Magnolia LNG Liquefaction Transport	Upgrades to existing pipeline system to provide 700,000 Dth/d capacity to serve Magnolia LNG in the Lake Charles, La., area. Subscribed under long-term firm agreements, subject to shipper's final investment decision.	Expected in-service fourth quarter 2020	$127 million
KMLP Sabine Pass Expansion	Reconfiguration to flow northeast to southeast to deliver 600,000 Dth/d to the Cheniere Sabine Pass Liquefaction Terminal in Cameron Parish, LA. Subscribed under long-term firm transportation contracts.	Expected in-service fourth quarter 2019	$151 million
TGP Orion	An expansion project to provide an additional 135,000 Dth/d of firm capacity from the Marcellus supply basin to TGP's interconnection with Columbia Gas Transmission in Pike County, Pennsylvania. Subscribed under long-term firm transportation contracts.	Expected in service June 2018.	$141 million
TGP Lone Star	Two Greenfield compressor stations to provide supply to the Corpus Christi LNG liquefaction project, for a capacity of 300,000 Dth/d. Subscribed under long-term firm transportation contracts.	Expected in-service July 2019.	$134 million
NGPL Gulf Coast Southbound Expansion	Expansion project, which is fully subscribed under long-term contracts, is designed to transport 460,000 Dth/d of incremental firm transportation service from NGPL's interstate pipeline interconnects in Illinois, Arkansas and Texas to points south on NGPL's pipeline system to serve growing demand in the Gulf Coast area.	Pending regulatory approvals, the project is expected in service by the fourth quarter of 2018.	$106 million
TGP Connecticut Expansion	Project will upgrade portions of TGP's existing system in New York, Massachusetts and Connecticut, and provide 72,100 Dth/d of additional firm transportation capacity for three local distribution company customers.	Expected in-service November 2017.	$93 million
TGP Triad Expansion	Expansion project that provides 180,000 Dth/d of long-term capacity for Invenergy's Lackawanna Energy Center in Lackawanna County, PA. Subscribed under long-term firm transportation contracts.	Expected in service between November 2017 and June 2018.	$69 million
Terminals			
Jones Act Tankers	Purchase of five medium-range Jones Act tankers constructed by General Dynamics' NASSCO Shipyard in San Diego. All of the tankers will be 50,000-deadweight-ton, LNG conversion-ready product carriers, with a capacity of 330,000 barrels and contracted for an average of 5 years. Also purchase of four new 50,000-deadweight-ton Tier II tankers constructed by Philly Shipyard. Each LNG conversion-ready will have a capacity of 337,000 barrels.	First tanker delivery took place in December 2015. Four additional tankers were delivered during 2016. The remaining four tankers are scheduled to be delivered through the end of 2017.	$1.4 billion
KM Export Terminal	Brownfield expansion along Houston Ship Channel will add 12 storage tanks with 1.5 million barrels of liquids	Storage tanks placed in service in January 2017 with	$246 million

	storage capacity, one ship dock, one barge dock and cross-channel pipelines to connect with the KM Galena Park terminal. Supported by a long-term contract with a major ship channel refiner.	the terminal's full marine capabilities to follow by the end of the first quarter 2017.	
KM Base Line Terminal development	Announced a 50-50 joint venture with Keyera Corp. to build a new 4.8 million barrels of merchant crude oil storage facility in Edmonton, Alberta. Subscribed under long-term contracts with an average initial term of 7.5 years.	Construction continues. Commissioning expected to begin in the first quarter of 2018 with tanks phased-into service throughout 2018.	CAD$372 million
Pit 11 Expansion Project	Adds 2 million barrels of refined products storage at Pasadena terminal, along the Houston Ship Channel. Supported by long-term commitments from existing customers.	Commissioning is expected to begin in the third quarter of 2017, with the tanks phased into service through the first quarter of 2018.	$185 million
Products Pipelines			
Utopia Pipeline	Building of new 215 mile pipeline, supported by a long-term customer contract, to transport ethane and ethane-propane mixtures from the prolific Utica Shale, with an initial design capacity of 50,000 barrels per day, expandable to more than 75,000 barrels per day.	Expected in service January 2018.	$540 million

Asset or project	Description	Activity	Approx. Capital Scope
Kinder Morgan Canada			
Trans Mountain Expansion Project	An increase of capacity on our Trans Mountain pipeline system from approximately 300,000 to 890,000 barrels per day, underpinned by long-term take-or-pay contracts.	Received federal government approval in December 2016. Construction is planned to begin in September 2017. Expected in service in December 2019.	$5.4 billion

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n/a - not applicable

Financings

On August 16, 2016, our wholly owned subsidiary, CIG, completed a private offering of $375 million in aggregate principal amount of 4.15% senior notes due August 15, 2026. On September 30, 2016 and October 1, 2016, a portion of the proceeds from the sale of a 50% interest in SNG was used to repay all of the $332 million principal amount outstanding of Copano’s 7.125% senior notes due 2021, plus accrued interest and all of the $749 million principal amount outstanding of Hiland’s 7.25% senior notes due 2020, plus accrued interest, respectively.

Current Commodity Price Environment

Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” as well as Note 4 “Impairments and Losses on Divestitures” and Note 8 “Goodwill” to our consolidated financial statements, discuss the impacts of the current commodity price environment on the energy industry, including our customers and us. Refer to the developments addressed in these sections, including the resulting non-cash impairment charges related to goodwill, certain long-lived assets and equity method investments. For a more general discussion of these related risk factors, refer to Item 1A. “Risk Factors.”

2017 Outlook

We expect to declare dividends of $0.50 per share for 2017 and generate approximately $4.46 billion of distributable cash flow. We also expect to invest $3.2 billion on expansion projects during 2017 to be funded with internally generated cash flow without the need to access equity markets. Our 2017 budget assumes a joint venture partner on our Trans Mountain expansion project and contributions from that partner to fund its share of expansion capital, but does not include any potential proceeds in excess of the partner’s share of expansion capital to recognize the value created in developing the project to this stage. We are unable to provide budgeted net income attributable to common stockholders (the GAAP financial measure most directly comparable to distributable cash flow) due to the inherent difficulty and impracticality 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.

These expectations assume an average 2017 WTI crude oil price of $53 per barrel and an average 2017 Henry Hub natural gas price of $3 per MMBtu, which were consistent with the current forward curve at the time that our 2017 budget was prepared.

The overwhelming majority of cash we generate is supported by multi-year fee-based customer arrangements and therefore is not directly exposed to commodity prices. The primary area where we have direct commodity price sensitivity is in our CO_2 segment, where we hedge the majority of the next 12 months of oil production to minimize this sensitivity. For 2017, we estimate that every $1 change in the average WTI crude oil price per barrel would impact our distributable cash flow by approximately $6 million and each $0.10 per MMBtu change in the average price of natural gas would impact distributable cash flow by approximately $1 million.

In addition, our expectations for 2017 discussed above involve risks, uncertainties and assumptions, and are not guarantees of performance. Many of the factors that will determine these expectations are beyond our ability to control or predict, and because of these uncertainties, it is advisable to not put undue reliance on any forward-looking statement. Please read our Item 1A “Risk Factors” below for more information. Furthermore, we plan to provide updates to our 2017 expectations when we believe previously disclosed expectations no longer have a reasonable basis.

(b) Financial Information about Segments

For financial information on our five reportable business segments, see Note 16 “Reportable Segments” to our consolidated financial statements.

(c) Narrative Description of Business

Business Strategy

Our business strategy is to:

- focus on stable, fee-based energy transportation and storage assets that are central to the energy infrastructure of growing markets within North America;
- increase utilization of our existing assets while controlling costs, operating safely, and employing environmentally sound operating practices;
- leverage economies of scale from incremental acquisitions and expansions of assets that fit within our strategy and are accretive to cash flow; and
- maintain a strong balance sheet and return value to our stockholders.

It is our intention to carry out the above business strategy, modified as necessary to reflect changing economic conditions and other circumstances. However, as discussed under Item 1A. “Risk Factors” below, there are factors that could affect our ability to carry out our strategy or affect its level of success even if carried out.

We regularly consider and enter into discussions regarding potential acquisitions, and full and partial divestitures, and we are currently contemplating potential transactions. Any such transaction would be subject to negotiation of mutually agreeable terms and conditions, receipt of fairness opinions, and approval of our board of directors, if applicable. While there are currently no unannounced purchase or sale agreements for the acquisition or sale of any material business or assets, such transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets or operations.

Business Segments

We operate the following reportable business segments. These segments and their principal sources of revenues are as follows:

- Natural Gas Pipelines—the ownership and operation of (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas and crude oil gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG facilities;
- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium for recovering crude oil from mature oil fields to increase production; (ii) ownership interests in and/or operation of oil fields and gas processing plants in West Texas; and (iii) the ownership and operation of a crude oil pipeline system in West Texas;
- Terminals—the ownership and/or operation of (i) liquids and bulk terminal facilities located throughout the U.S. and portions of Canada that transload and store refined petroleum products, crude oil, chemicals, and ethanol and bulk products, including coal, petroleum coke, fertilizer, steel and ores and (ii) Jones Act tankers;
- Products Pipelines—the ownership and operation of refined petroleum products, NGL and crude oil and condensate pipelines that primarily deliver, among other products, gasoline, diesel and jet fuel, propane, crude oil and condensate to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities; and
- Kinder Morgan Canada—the ownership and operation of the Trans Mountain pipeline system that transports crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia, Canada and the state of Washington, plus the Jet Fuel aviation turbine fuel pipeline that serves the

Vancouver (Canada) International Airport.

Natural Gas Pipelines

Our Natural Gas Pipelines segment includes interstate and intrastate pipelines and our LNG terminals, and includes both FERC regulated and non-FERC regulated assets.

Our primary businesses in this segment consist of natural gas sales, transportation, storage, gathering, processing and treating, and the terminaling of LNG. Within this segment, are: (i) approximately 46,000 miles of natural gas pipelines and (ii) our equity interests in entities that have approximately 26,000 miles of natural gas pipelines, along with associated storage and supply lines for these transportation networks, which are strategically located throughout the North American natural gas pipeline grid. Our transportation network provides access to the major natural gas supply areas and consumers in the western U.S., Louisiana, Texas, the Midwest, Northeast, Rocky Mountain, Midwest and Southeastern regions. Our LNG storage and regasification terminals also serve natural gas supply areas in the southeast. The following tables summarize our significant Natural Gas Pipelines segment assets, as of December 31, 2016. The Design Capacity represents either transmission, gathering or liquefaction capacity depending on the nature of the asset.

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Design (Bcf/d) Capacity	Storage (Bcf) [Processing (Bcf/d)] Capacity	Supply and Market Region
Natural Gas Pipelines				
TGP	11,800	10.23	104	North to south to Gulf Coast and U.S.-Mexico border, southeast U.S.; Haynesville, Marcellus, Utica, and Eagle Ford shale formations
EPNG/Mojave pipeline system	10,600	5.65	44	Northern New Mexico, Texas, Oklahoma, to California, connects to San Juan, Permian and Anadarko basins
NGPL (50%)	9,100	6.90	288	Chicago and other Midwest markets and all central U.S. supply basins; north to south for LNG and to U.S.-Mexico border
SNG (50%)	6,900	4.07	68	Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee; basins in Texas, Louisiana, Mississippi and Alabama
Florida Gas Transmission (Citrus) (50%)	5,300	3.60	—	Texas to Florida; basins along Louisiana and Texas Gulf Coast, Mobile Bay and offshore Gulf of Mexico
CIG	4,350	5.15	37	Colorado and Wyoming; Rocky Mountains and the Anadarko Basin
WIC	850	3.88	—	Wyoming, Colorado and Utah; Overthrust, Piceance, Uinta, Powder River and Green River Basins
Ruby pipeline (50%)	680	1.53	—	Wyoming to Oregon; Rocky Mountain basins
MEP (50%)	510	1.80	—	Oklahoma and north Texas supply basins to interconnects with deliveries to interconnects with Transco, Columbia Gulf and various other pipelines
CPG	410	1.20	—	Colorado and Kansas, natural gas basins in the Central Rocky Mountain area
TransColorado Gas	310	0.98	—	Colorado and New Mexico; connects to San Juan, Paradox and Piceance basins
WYCO (50%)	224	1.20	7	Northeast Colorado; interconnects with CIG, WIC, Rockies Express Pipeline, Young Gas Storage and PSCo's pipeline system
Elba Express	200	0.95	—	Georgia; connects to SNG (Georgia), Transco (Georgia/South Carolina), SLNG (Georgia) and CGT (Georgia).
FEP (50%)	185	2.00	—	Arkansas to Mississippi; connects to NGPL, Trunkline Gas Company, Texas Gas Transmission

				and ANR Pipeline Company
KMLP	135	2.20	—	sources gas from Cheniere Sabine Pass LNG terminal to interconnects with Columbia Gulf, ANR and various other pipelines
Sierrita Gas Pipeline LLC (35%)	61	0.20	—	near Tucson, Arizona, to the U.S.-Mexico border near Sasabe, Arizona; connects to EPNG and via an international border crossing with a third-party natural gas pipeline in Mexico
Young Gas Storage (48%)	16	—	6	Morgan County, Colorado, capacity is committed to CIG and Colorado Springs Utilities
Keystone Gas Storage	12	—	6	located in the Permian Basin and near the WAHA natural gas trading hub in West Texas
Gulf LNG Holdings (50%)	5	—	6.6	near Pascagoula, Mississippi; connects to four interstate pipelines and a natural gas processing plant
Bear Creek Storage (75%)	—	—	59	located in Louisiana; provides storage capacity to SNG and TGP

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Design (Bcf/d) Capacity	Storage (Bcf) [Processing (Bcf/d)] Capacity	Supply and Market Region
SLNG	—	—	11.5	Georgia; connects to Elba Express, SNG and CGT
ELC	—	0.35	—	Georgia; expect phased in service from mid-2018 to early 2019
Midstream Natural Gas Assets				
KM Texas and Tejas pipelines	5,650	6.40	136 [0.51]	Texas Gulf Coast
Mier-Monterrey pipeline	90	0.65	—	Starr County, Texas to Monterrey, Mexico; connect to CENEGAS national system and multiple power plants in Monterrey
KM North Texas pipeline	80	0.33	—	interconnect from NGPL; connects to 1,750-megawatt Forney, Texas, power plant and a 1,000-megawatt Paris, Texas, power plant
Oklahoma				
Oklahoma System	3,500	0.35	[0.15]	Hunton Dewatering, Woodford Shale and Mississippi Lime
Hiland - Midcontinent	622	0.20	—	Woodford Shale, Anadarko Basin and Arkoma Basin
Southern Dome (73%)	—	—	[0.02]	currently idle
Cedar Cove (70%)	89	0.03	[0.01]	Oklahoma STACK, capacity excludes third-party offloads
South Texas				
South Texas System	1,300	1.74	[1.06]	Eagle Ford shale, Woodbine and Eaglebine formations
Webb/Duval gas gathering system (63%)	145	0.15	—	South Texas
EagleHawk (25%)	590	1.20	—	South Texas, Eagle Ford shale formation
KM Altamont	1,350	0.08	[0.08]	Utah, Uinta Basin
Red Cedar (49%)	750	0.70	—	La Plata County, Colorado, Ignacio Blanco Field
Rocky Mountain				
Fort Union (37%)	310	1.25	—	Powder River Basin (Wyoming)
Bighorn (51%)	290	0.60	—	Powder River Basin (Wyoming)
KinderHawk	500	2.00	—	Northwest Louisiana, Haynesville and Bossier shale formations
North Texas	550	0.14	[0.10]	North Barnett Shale Combo
Endeavor (40%)	101	0.15	—	East Texas, Cotton Valley Sands and Haynesville/ Bossier Shale
Camino Real	70	0.15	—	South Texas, Eagle Ford shale formation
KM Treating	—	—	—	Odessa, Texas, other locations in Tyler and Victoria, Texas
Hiland - Williston	2,000	0.31	[0.20]	Bakken/Three Forks shale formations (North Dakota/Montana)

Midstream Liquids/Oil/Condensate Pipelines

		(MBbl/d)	(MBbl)	
Liberty Pipeline (50%)	87	170	—	Y-grade pipeline from Houston Central complex to the Texas Gulf Coast
South Texas NGL Pipelines	340	115	—	Ethane and propane pipelines from Houston Central complex to the Texas Gulf Coast
Camino Real - Condensate	68	110	20	South Texas, Eagle Ford shale formation
Hiland - Williston - Oil	1,480	240	—	Bakken/Three Forks shale formations (North Dakota/Montana)
EagleHawk - Condensate (25%)	410	220	60	South Texas, Eagle Ford shale formation

Competition

The market for supply of natural gas is highly competitive, and new pipelines, storage facilities, treating facilities, and facilities for related services are currently being built to serve the growing demand for natural gas in each of the markets served by the pipelines in our Natural Gas Pipelines business segment. Our operations compete with interstate and intrastate pipelines, and their shippers, for connections to new markets and supplies and for transportation, processing and treating services. We believe the principal elements of competition in our various markets are location, rates, terms of service and flexibility and reliability of service. From time to time, other projects are proposed that would compete with us. We do not know whether or when any such projects would be built, or the extent of their impact on our operations or profitability.

Shippers on our natural gas pipelines compete with other forms of energy available to their natural gas customers and end users, including electricity, coal, propane, fuel oils and renewables such as wind and solar. Several factors influence the demand for natural gas, including price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation and governmental regulations, the ability to convert to alternative fuels and weather.

CO_2

Our CO_2 business segment produces, transports, and markets CO_2 for use in enhanced oil recovery projects as a flooding medium for recovering crude oil from mature oil fields. Our CO_2 pipelines and related assets allow us to market a complete package of CO_2 supply, transportation and technical expertise to our customers. We also hold ownership interests in several oil-producing fields and own a crude oil pipeline, all located in the Permian Basin region of West Texas.

Sales and Transportation Activities

Our principal market for CO_2 is for injection into mature oil fields in the Permian Basin, where industry demand is expected to remain stable for the next several years. Our ownership of CO_2 resources as of December 31, 2016 includes:

	Ownership Interest %	Recoverable CO_2 (Bcf)	Compression Capacity (Bcf/d)	Location
Recoverable CO_2				
McElmo Dome unit(a)	45	4,570	1.5	Colorado
Doe Canyon Deep unit(a)	87	420	0.2	Colorado
Bravo Dome unit	11	367	0.3	New Mexico

(a) We also operate this unit.

CO_2 Segment Pipelines

The principal market for transportation on our CO_2 pipelines is to customers, including ourselves, using CO_2 for enhanced recovery operations in mature oil fields in the Permian Basin, where industry demand is expected to remain stable for the next several years. The tariffs charged on the Wink pipeline system are regulated by both the FERC and the Texas Railroad Commission and the Pecos Carbon Dioxide Pipeline’s tariffs are regulated by the Texas Railroad Commission. The tariff charged on the Cortez pipeline is based on a consent decree and the tariffs charged by our other CO_2 pipelines are not regulated.

Our ownership of CO_2 and crude oil pipelines as of December 31, 2016 includes:

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Transport Capacity(Bcf/d)	Supply and Market Region
CO_2 pipelines			
Cortez pipeline (50%)	569	1.5	McElmo Dome and Doe Canyon source fields to the Denver City, Texas hub
Central Basin pipeline	334	0.7	Cortez, Bravo, Sheep Mountain, Canyon Reef Carriers, and Pecos pipelines
Bravo pipeline (13%)(a)	218	0.4	Bravo Dome to the Denver City, Texas hub
Canyon Reef Carriers pipeline (98%)	163	0.3	McCamey, Texas, to the SACROC, Sharon Ridge, Cogdell and Reinecke units
Centerline CO_2 pipeline	113	0.3	between Denver City, Texas and Snyder, Texas
Eastern Shelf CO_2 pipeline	98	0.1	between Snyder, Texas and Knox City, Texas
Pecos pipeline (95%)	25	0.1	McCamey, Texas, to Iraan, Texas, delivers to the Yates unit
Goldsmith Landreth (99%)	3	0.2	Goldsmith Landreth San Andres field in the Permian Basin of West Texas
		(Bbls/d)	
Crude oil pipeline			
Wink pipeline	457	145,000	West Texas to Western Refining's refinery in El Paso, Texas

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(a) We do not operate Bravo pipeline.

Oil and Gas Producing Activities

Oil Producing Interests

Our ownership interests in oil-producing fields located in the Permian Basin of West Texas, include the following:

	Working Interest %	KMI Gross Developed Acres
SACROC	97	49,156
Yates	50	9,576
Goldsmith Landreth San Andres	99	6,166
Katz Strawn	99	7,194
Sharon Ridge	14	2,619
Tall Cotton (ROZ)	100	641
MidCross	13	320
Reinecke(a)	—	80

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(a) Working interest less than 1 percent.

The following table sets forth productive wells, service wells and drilling wells in the oil and gas fields in which we owned interests as of December 31, 2016. The oil and gas producing fields in which we own interests are located in the Permian Basin area of West Texas. When used with respect to acres or wells, "gross" refers to the total acres or wells in which we have a working interest, and "net" refers to gross acres or wells multiplied, in each case, by the percentage working interest owned by us:

	Productive Wells(a)		Service Wells(b)		Drilling Wells(c)	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	2,239	1,447	1,227	984	6	6
Natural Gas	5	2	—	—	—	—
Total Wells	2,244	1,449	1,227	984	6	6

(a) Includes active wells and wells temporarily shut-in. As of December 31, 2016, we did not operate any productive wells with multiple completions.
(b) Consists of injection, water supply, disposal wells and service wells temporarily shut-in. A disposal well is used for disposal of salt water into an underground formation; and an injection well is a well drilled in a known oil field in order to inject liquids and/or gases that enhance recovery.
(c) Consists of development wells in the process of being drilled as of December 31, 2016. A development well is a well drilled in an already discovered oil field.

The following table reflects our net productive wells that were completed in each of the years ended December 31, 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015	2014
Productive			
Development	40	87	84
Exploratory	3	20	10
Total Productive	43	107	94
Dry Exploratory	—	—	1
Total Wells	43	107	95

Note: The above table includes wells that were completed during each year regardless of the year in which drilling was initiated, and does not include any wells where drilling and completion operations were not finalized as of the end of the applicable year. A completed well refers to the installation of permanent equipment for the production of oil and gas. A development well is a well drilled in an already discovered oil field. A dry hole is reflected once the well has been abandoned and reported to the appropriate governmental agency. Prior year amounts have been adjusted to be consistent with the current period presentation.

The following table reflects the developed and undeveloped oil and gas acreage that we held as of December 31, 2016:

	Gross	Net
Developed Acres	75,752	72,561
Undeveloped Acres	17,282	15,093
Total	93,034	87,654

Note: As of December 31, 2016, we have no material amount of acreage expiring in the next three years.

Our oil and gas producing activities are not significant and therefore, we do not include the supplemental information on oil and gas producing activities under Accounting Standards Codification Topic 932, Extractive Activities - Oil and Gas.

Gas and Gasoline Plant Interests

Operated gas plants in the Permian Basin of West Texas:

	Ownership Interest %	Source
Snyder gasoline plant(a)	22	The SACROC unit and neighboring CO_2 projects, specifically the Sharon Ridge and Cogdell units
Diamond M gas plant	51	Snyder gasoline plant
North Snyder plant	100	Snyder gasoline plant

(a) This is a working interest, in addition, we have a 28% net profits interest. The average net to us does not include the value associated with the net profits interest.

Competition

Our primary competitors for the sale of CO_2 include suppliers that have an ownership interest in McElmo Dome, Bravo Dome and Sheep Mountain CO_2 resources, and Oxy U.S.A., Inc., which controls waste CO_2 extracted from natural gas production in the Val Verde Basin of West Texas. Our ownership interests in the Central Basin, Cortez and Bravo pipelines are in direct competition with other CO_2 pipelines. We also compete with other interest owners in the McElmo Dome unit and the Bravo Dome unit for transportation of CO_2 to the Denver City, Texas market area.

Terminals

Our Terminals segment includes the operations of our refined petroleum product, crude oil, chemical, ethanol and other liquid terminal facilities (other than those included in the Products Pipelines segment) and all of our coal, petroleum coke, fertilizer, steel, ores and other dry-bulk terminal facilities. Our terminals are located throughout the U.S. and in portions of Canada. We believe the location of our facilities and our ability to provide flexibility to customers help attract new and retain existing customers at our terminals and provide expansion opportunities. We often classify our terminal operations based on the handling of either liquids or dry-bulk material products. In addition, Terminals' marine operations include Jones Act qualified product tankers that provide marine transportation of crude oil, condensate and refined petroleum products in the U.S. The following summarizes our Terminals segment assets, as of December 31, 2016:

	Number	Capacity (MMBbl)
Liquids terminals	51	85.2
Bulk terminals	37	—
Jones Act tankers	12	4.0

Competition

We are one of the largest independent operators of liquids terminals in North America, based on barrels of liquids terminaling capacity. Our liquids terminals compete with other publicly or privately held independent liquids terminals, and terminals owned by oil, chemical, pipeline, and refining companies. Our bulk terminals compete with numerous independent terminal operators, terminals owned by producers and distributors of bulk commodities, stevedoring companies and other industrial companies opting not to outsource terminaling services. In some locations, competitors are smaller, independent operators with lower cost structures. Our Jones Act qualified product tankers compete with other Jones Act qualified vessel fleets.

Products Pipelines

Our Products Pipelines segment consists of our refined petroleum products, crude oil and condensate, and NGL pipelines and associated terminals, Southeast terminals, our condensate processing facility and our transmix processing facilities. The following summarizes our significant Products Pipelines segment assets we own and operate as of December 31, 2016:

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Number of Terminals (a) or locations	Terminal Capacity(MMBbl)	Supply and Market Region
Plantation pipeline (51%)	3,182	—	—	Louisiana to Washington D.C.
West Coast Products Pipelines(b)				
Pacific (SFPP)	2,823	13	15.5	six western states
Calnev	570	2	2.1	Colton, CA to Las Vegas, NV; Mojave region
West Coast Terminals	43	7	10.1	Seattle, Portland, San Francisco and Los Angeles areas
Cochin pipeline	1,877	4	1.1	three provinces in Canada and seven states in the U.S.
KM Crude & Condensate pipeline	252	5	2.6	Eagle Ford shale field in South Texas (Dewitt, Karnes, and Gonzales Counties) to the Houston ship channel refining complex
Double H Pipeline	511	—	—	Bakken shale in Montana and North Dakota to Guernsey, Wyoming
Central Florida pipeline	206	2	2.5	Tampa to Orlando
Double Eagle pipeline (50%)	194	2	0.6	Live Oak County, Texas; Corpus Christi, Texas; Karnes County, Texas; and LaSalle County
Cypress pipeline (50%)	104			Mont Belvieu, Texas to Lake Charles, Louisiana
Southeast Terminals	—	32	10.8	from Mississippi through Virginia, including Tennessee
KM Condensate Processing Facility	—	1	1.9	Houston Ship Channel, Galena Park, Texas
Transmix Operations	—	5	1.0	Colton, California; Richmond, Virginia; Dorsey Junction, Maryland; St. Louis, Missouri; and Greensboro, North Carolina

(a) The terminals provide services including short-term product storage, truck loading, vapor handling, additive injection, dye injection and ethanol blending.

(b) Our West Coast Products Pipelines assets include interstate common carrier pipelines rate-regulated by the FERC, intrastate pipelines in the state of California rate-regulated by the CPUC, and certain non rate-regulated operations and terminal facilities.

Competition

Our Products Pipelines’ pipeline operations compete against proprietary pipelines owned and operated by major oil companies, other independent products pipelines, trucking and marine transportation firms (for short-haul movements of products) and railcars. Our Products Pipelines’ terminal operations compete with proprietary terminals owned and operated by major oil companies and other independent terminal operators, and our transmix operations compete with refineries owned by major oil companies and independent transmix facilities.

Kinder Morgan Canada

Our Kinder Morgan Canada business segment includes our 100% owned and operated Trans Mountain pipeline system and a 25-mile Jet Fuel pipeline system.

Trans Mountain Pipeline System

The Trans Mountain pipeline system originates at Edmonton, Alberta and transports crude oil and refined petroleum products to destinations in the interior and on the west coast of British Columbia. The Trans Mountain pipeline is 713 miles in length. We also own and operate a connecting pipeline that delivers crude oil to refineries in the state of Washington. The capacity of the line at Edmonton ranges from 300 MBbl/d when heavy crude oil represents 20% of the total throughput (which is a historically normal heavy crude oil percentage), to 400 MBbl/d with no heavy crude oil.

Jet Fuel Pipeline System

We also own and operate the approximate 25-mile aviation fuel pipeline that serves the Vancouver International Airport, located in Vancouver, British Columbia, Canada. The turbine fuel pipeline is referred to in this report as the Jet Fuel pipeline system. In addition to its receiving and storage facilities located at the Westridge Marine terminal, located in Port Metro Vancouver, the Jet Fuel pipeline system's operations include a terminal at the Vancouver airport that consists of five jet fuel storage tanks with an overall capacity of 15 MBbl.

Competition

Trans Mountain is one of several pipeline alternatives for western Canadian crude oil and refined petroleum production, and it competes against other pipeline providers; however, it is the sole pipeline carrying crude oil and refined petroleum products from Alberta to the west coast. Furthermore, as demonstrated by our previously announced expansion proposal, discussed above in "—(a) General Development of Business—Recent Developments—Kinder Morgan Canada," we believe that the Trans Mountain pipeline facilities provide us the opportunity to execute on capacity expansions to the west coast as the market for offshore exports continues to develop.

In December 2013, the British Columbia Ministry of Environment granted approval for a new, airport fuel consortium owned, jet fuel terminal to be located near the Vancouver International Airport. The impact of this facility on our existing Jet Fuel pipeline system is uncertain at this time.

Major Customers

Our revenue is derived from a wide customer base. For each of the years ended December 31, 2016, 2015 and 2014, no revenues from transactions with a single external customer accounted for 10% or more of our total consolidated revenues. Our Texas Intrastate Natural Gas Pipeline operations (includes the operations of Kinder Morgan Tejas Pipeline LLC, Kinder Morgan Border Pipeline LLC, Kinder Morgan Texas Pipeline LLC, Kinder Morgan North Texas Pipeline LLC and the Mier-Monterrey Mexico pipeline system) buys and sells significant volumes of natural gas within the state of Texas, and, to a far lesser extent, the CO_2 business segment also sells natural gas. Combined, total revenues from the sales of natural gas from the Natural Gas Pipelines and CO_2 business segments in 2016, 2015 and 2014 accounted for 19%, 20% and 25%, respectively, of our total consolidated revenues. To the extent possible, we attempt to balance the pricing and timing of our natural gas purchases to our natural gas sales, and these contracts are often settled in terms of an index price for both purchases and sales. We do not believe that a loss of revenues from any single customer would have a material adverse effect on our business, financial position, results of operations or cash flows.

Regulation

Interstate Common Carrier Refined Petroleum Products and Oil Pipeline Rate Regulation - U.S. Operations

Some of our U.S. refined petroleum products and crude oil gathering and transmission pipelines are interstate common carrier pipelines, subject to regulation by the FERC under the Interstate Commerce Act, or ICA. The ICA requires that we maintain our tariffs on file with the FERC. Those tariffs set forth the rates we charge for providing gathering or transportation services on our interstate common carrier pipelines as well as the rules and regulations governing these services. The ICA requires, among other things, that such rates on interstate common carrier pipelines be "just and reasonable" and nondiscriminatory. The ICA permits interested persons to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff collected during the pendency of the investigation. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained during the two years prior to the filing of a complaint.

The Energy Policy Act of 1992 deemed petroleum products pipeline tariff rates that were in effect for the 365-day period ending on the date of enactment or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period to be just and reasonable or “grandfathered” under the ICA. The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates.

Certain rates on our Pacific operations' pipeline system were subject to protest during the 365-day period established by the Energy Policy Act. Accordingly, certain of the Pacific pipelines' rates have been, and continue to be, the subject of complaints with the FERC, as is more fully described in Note 17 "Litigation, Environmental and Other Contingencies" to our consolidated financial statements.

Petroleum products pipelines may change their rates within prescribed ceiling levels that are tied to an inflation index. Shippers may protest rate increases made within the ceiling levels, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs from the previous year. A pipeline must, as a general rule, utilize the indexing methodology to change its rates.

Cost-of-service ratemaking, market-based rates and settlement rates are alternatives to the indexing approach and may be used in certain specified circumstances to change rates.

Common Carrier Pipeline Rate Regulation - Canadian Operations

The Canadian portion of our crude oil and refined petroleum products pipeline systems is under the regulatory jurisdiction of the NEB. The National Energy Board Act gives the NEB power to authorize pipeline construction and to establish tolls and conditions of service. Our subsidiary Trans Mountain Pipeline, L.P. is the sole owner of our Trans Mountain crude oil and refined petroleum products pipeline system.

The toll charged for the portion of Trans Mountain's pipeline system located in the U.S. falls under the jurisdiction of the FERC. For further information, see "—Interstate Common Carrier Refined Petroleum Products and Oil Pipeline Rate Regulation - U.S. Operations" above.

Interstate Natural Gas Transportation and Storage Regulation

Posted tariff rates set the general range of maximum and minimum rates we charge shippers on our interstate natural gas pipelines. Within that range, each pipeline is permitted to charge discounted rates, so long as such discounts are offered to all similarly situated shippers and granted without undue discrimination. Apart from discounted rates offered within the range of tariff maximums and minimums, the pipeline is permitted to charge negotiated rates where the pipeline and shippers want rate certainty, irrespective of changes that may occur to the range of tariff-based maximum and minimum rate levels. Negotiated rates provide certainty to the pipeline and the shipper of agreed upon rates during the term of the transportation agreement, regardless of changes to the posted tariff rates. There are a variety of rates that different shippers may pay, but while the rates may vary by shipper and circumstance, pipelines must generally use the form of service agreement that is contained within their FERC approved tariff. Any deviation from the pro forma service agreements must be filed with the FERC and only certain types of deviations are acceptable to the FERC.

The FERC regulates the rates, terms and conditions of service, construction and abandonment of facilities by companies performing interstate natural gas transportation services, including storage services, under the Natural Gas Act of 1938. To a lesser extent, the FERC regulates interstate transportation rates, terms and conditions of service under the Natural Gas Policy Act of 1978. Beginning in the mid-1980's, the FERC initiated a number of regulatory changes intended to ensure that interstate natural gas pipelines operated on a not unduly discriminatory basis and to create a more competitive and transparent environment in the natural gas marketplace. Among the most important of these changes were:

- Order No. 436 (1985) which required open-access, nondiscriminatory transportation of natural gas;
- Order No. 497 (1988) which set forth new standards and guidelines imposing certain constraints on the interaction between interstate natural gas pipelines and their marketing affiliates and imposing certain disclosure requirements regarding that interaction;
- Order Nos. 587, et seq., Order No. 809 (1996-2015) which adopt regulations to standardize the business practices and communication methodologies of interstate natural gas pipelines to create a more integrated and efficient pipeline grid and wherein the FERC has incorporated by reference in its regulations standards for interstate natural gas pipeline business practices and electronic communications that were developed and adopted by the North American Energy Standards Board (NAESB). Interstate natural gas pipelines are required to incorporate by reference or verbatim in their respective tariffs the applicable version of the NAESB standards;
- Order No. 636 (1992) which required interstate natural gas pipelines that perform open-access transportation under blanket certificates to "unbundle" or separate their traditional merchant sales services from their transportation and storage services and to provide comparable transportation and storage services with respect to all natural gas supplies.

Natural gas pipelines must now separately state the applicable rates for each unbundled service they provide (i.e., for the natural gas commodity, transportation and storage);

- Order No. 637 (2000) which revised, among other things, FERC regulations relating to scheduling procedures, capacity segmentation, and pipeline penalties in order to improve the competitiveness and efficiency of the interstate pipeline grid; and
- Order No. 717 (2008) amending the Standards of Conduct for Transmission Providers (the Standards of Conduct or the Standards) to make them clearer and to refocus the marketing affiliate rules on the areas where there is the greatest potential for abuse. The FERC standards of conduct address and clarify multiple issues with respect to the actions and operations of interstate natural gas pipelines and public utilities using a functional approach to ensure that natural gas transmission is provided on a nondiscriminatory basis, including (i) the definition of transmission function and transmission function employees; (ii) the definition of marketing function and marketing function employees; (iii) the definition of transmission function information and non-disclosure requirements regarding non-public information; (iv) independent functioning and no conduit requirements; (v) transparency requirements; and (vi) the interaction of FERC standards with the NAESB business practice standards. The Standards of Conduct rules also require that a transmission provider provide annual training on the standards of conduct to all transmission function employees, marketing function employees, officers, directors, supervisory employees, and any other employees likely to become privy to transmission function information.

In addition to regulatory changes initiated by the FERC, the U.S. Congress passed the Energy Policy Act of 2005. Among other things, the Energy Policy Act amended the Natural Gas Act to: (i) prohibit market manipulation by any entity; (ii) direct the FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce; and (iii) significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or FERC rules, regulations or orders thereunder.

CPUC Rate Regulation

The intrastate common carrier operations of our Pacific operations’ pipelines in California are subject to regulation by the CPUC under a “depreciated book plant” methodology, which is based on an original cost measure of investment. Intrastate tariffs filed by us with the CPUC have been established on the basis of revenues, expenses and investments allocated as applicable to the California intrastate portion of the Pacific operations’ business. Tariff rates with respect to intrastate pipeline service in California are subject to challenge by complaint by interested parties or by independent action of the CPUC. A variety of factors can affect the rates of return permitted by the CPUC, and certain other issues similar to those which have arisen with respect to our FERC regulated rates also could arise with respect to its intrastate rates. The intrastate rates for movements in California on our SFPP and Calnev systems have been, and may in the future be, subject to complaints before the CPUC, as is more fully described in Note 17 “Litigation, Environmental and Other Contingencies” to our consolidated financial statements.

Railroad Commission of Texas (RCT) Rate Regulation

The intrastate operations of our crude oil and liquids pipelines and natural gas pipelines and storage facilities in Texas are subject to regulation with respect to such intrastate transportation by the RCT. The RCT has the authority to regulate our rates, though it generally has not investigated the rates or practices of our intrastate pipelines in the absence of shipper complaints.

Mexico - Energy Regulatory Commission

The Mier-Monterrey Pipeline has a natural gas transportation permit granted by the Energy Regulatory Commission (the Commission) that defines the conditions for the pipeline to carry out activity and provide natural gas transportation service. This permit expires in 2026.

This permit establishes certain restrictive conditions, including without limitations (i) compliance with the general conditions for the provision of natural gas transportation service; (ii) compliance with certain safety measures, contingency plans, maintenance plans and the official Mexican standards regarding safety; (iii) compliance with the technical and economic specifications of the natural gas transportation system authorized by the Commission; (iv) compliance with certain technical studies established by the Commission; and (v) compliance with a minimum contributed capital not entitled to withdrawal of at least the equivalent of 10% of the investment proposed in the project.

Mexico - Nacional Agency for Industrial Safety and Environmental Protection (ASEA)

ASEA regulates environmental compliance and industrial and operational safety. The Mier-Monterrey Pipeline must satisfy and maintain ASEA’s requirements, including compliance with certain safety measures, contingency plans, maintenance plans and the official Mexican standards regarding safety, including a Safety Administration Program.

Safety Regulation

We are also subject to safety regulations imposed by PHMSA, including those requiring us to develop and maintain pipeline Integrity Management programs to comprehensively evaluate areas along our pipelines and take additional measures to protect pipeline segments located in what are referred to as High Consequence Areas, or HCAs, where a leak or rupture could potentially do the most harm.

The ultimate costs of compliance with pipeline Integrity Management rules are difficult to predict. Changes such as advances of in-line inspection tools, identification of additional integrity threats and changes to the amount of pipe determined to be located in HCAs can have a significant impact on costs to perform integrity testing and repairs. We plan to continue our pipeline integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by PHMSA regulations. These tests could result in significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

The Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 or “PIPES Act of 2016” requires PHMSA, among others, to set minimum safety standards for underground natural gas storage facilities and allows states to go above those standards for intrastate pipelines. The Act also authorizes emergency order authority that is tailored to the pipeline sector, taking into account public health and safety, network, and customer impacts. The financial impact of these two requirements, if any, is unknown at this time.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which was signed into law in 2012, increased penalties for violations of safety laws and rules and may result in the imposition of more stringent regulations in the next few years. In 2012, PHMSA issued an Advisory Bulletin which, among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing, or other data to determine maximum pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the Advisory Bulletin requirements, could significantly increase our costs. Additionally, failure to locate such records to verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on our pipelines. There can be no assurance as to the amount or timing of future expenditures for pipeline Integrity Management regulation, and actual expenditures may be different from the amounts we currently anticipate. Regulations, changes to regulations or an increase in public expectations for pipeline safety may require additional reporting, the replacement of some of our pipeline segments, addition of monitoring equipment and more frequent inspection or testing of our pipeline facilities. Repair, remediation, and preventative or mitigating actions may require significant capital and operating expenditures.

From time to time, our pipelines may experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages caused by an alleged failure to properly mark the locations of our pipelines and/or to properly maintain our pipelines. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

We are also subject to the requirements of the Occupational Safety and Health Administration (OSHA) and other federal and state agencies that address employee health and safety. In general, we believe current expenditures are addressing the OSHA requirements and protecting the health and safety of our employees. Based on new regulatory developments, we may increase expenditures in the future to comply with higher industry and regulatory safety standards. However, such increases in our expenditures, and the extent to which they might be offset, cannot be estimated at this time.

State and Local Regulation

Our activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies, governing a wide variety of matters, including marketing, production, pricing, pollution, protection of the environment, and human health and safety.

Marine Operations

The operation of tankers and marine equipment create maritime obligations involving property, personnel and cargo under General Maritime Law. These obligations create a variety of risks including, among other things, the risk of collision, which may precipitate claims for personal injury, cargo, contract, pollution, third party claims and property damages to vessels and facilities.

We are subject to the Jones Act and other federal laws that restrict maritime transportation (between U.S. departure and destination points) to vessels built and registered in the U.S. and owned and manned by U.S. citizens. As a result, we monitor the foreign ownership of our common stock and under certain circumstances, consistent with our certificate of incorporation, we have the right to redeem shares of our common stock owned by non-U.S. citizens. If we do not comply with such requirements, we would be prohibited from operating our vessels in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of the vessels. Furthermore, from time to time, legislation has been introduced unsuccessfully in Congress to amend the Jones Act to ease or remove the requirement that vessels operating between U.S. ports be built and registered in the U.S. and owned and manned by U.S. citizens. If the Jones Act were amended in such fashion, we could face competition from foreign flagged vessels.

In addition, the U.S. Coast Guard and the American Bureau of Shipping maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for U.S.-flag operators than for owners of vessels registered under foreign flags of convenience. The Jones Act and General Maritime Law also provide damage remedies for crew members injured in the service of the vessel arising from employer negligence or vessel unseaworthiness.

The Merchant Marine Act of 1936 is a federal law that provides, upon proclamation by the U.S. President of a national emergency or a threat to the national security, the U.S. Secretary of Transportation the authority to requisition or purchase any vessel or other watercraft owned by U.S. citizens (including us, provided that we are considered a U.S. citizen for this purpose). If one of our vessels were purchased or requisitioned by the U.S. government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, we would not be entitled to compensation for any consequential damages suffered as a result of such purchase or requisition.

Environmental Matters

Our business operations are subject to federal, state, provincial and local laws and regulations relating to environmental protection, pollution and human health and safety in the U.S. and Canada. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines, or at or from our storage or other facilities, we may experience significant operational disruptions, and we may have to pay a significant amount to clean up the leak, release or spill, pay for government penalties, address natural resource damages, compensate for human exposure or property damage, install costly pollution control equipment or a combination of these and other measures. Furthermore, new projects may require approvals and environmental analysis under federal and state laws, including the National Environmental Policy Act and the Endangered Species Act. The resulting costs and liabilities could materially and negatively affect our business, financial condition, results of operations and cash flows. In addition, emission controls required under federal, state and provincial environmental laws could require significant capital expenditures at our facilities.

Environmental and human health and safety laws and regulations are subject to change. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, wildlife, natural resources and human health. There can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows.

In accordance with GAAP, we accrue liabilities for environmental matters when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets or businesses currently owned or previously disposed. We have accrued liabilities for estimable and probable environmental remediation obligations at various sites, including multi-party sites where the EPA, or similar state or Canadian agency has identified us as one of the potentially responsible parties. The involvement of other financially responsible companies at these multi-party sites could increase or mitigate our actual joint and several liability exposures.

We believe that the ultimate resolution of these environmental matters will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, it is possible that our ultimate liability with respect to these environmental matters could exceed the amounts accrued in an amount that could be material to our business, financial position, results of operations or cash flows in any particular reporting period. We have accrued an environmental reserve in the amount of $302 million as of December 31, 2016. Our aggregate reserve estimate ranges in value from approximately $302 million to approximately $477 million, and we recorded our liability equal to the low end of the range, as we did not identify any amounts within the range as a better estimate of the liability. For additional information related to environmental matters, see Note 17 “Litigation, Environmental and Other Contingencies” to our consolidated financial statements.

Hazardous and Non-Hazardous Waste

We generate both hazardous and non-hazardous wastes that are subject to the requirements of the Federal Resource Conservation and Recovery Act and comparable state and Canadian statutes. From time to time, the EPA and state and Canadian regulators consider the adoption of stricter disposal standards for non hazardous waste. Furthermore, it is possible that some wastes that are currently classified as non-hazardous, which could include wastes currently generated during our pipeline or liquids or bulk terminal operations, may in the future be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly handling and disposal requirements than non-hazardous wastes. Such changes in the regulations may result in additional capital expenditures or operating expenses for us.

Superfund

The CERCLA or the Superfund law, and analogous state laws, impose joint and several liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons for releases of hazardous substances into the environment. These persons include the owner or operator of a site and companies that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur, in addition to compensation for natural resource damages, if any. Although petroleum is excluded from CERCLA’s definition of a hazardous substance, in the course of our ordinary operations, we have and will generate materials that may fall within the definition of hazardous substance. By operation of law, if we are determined to be a potentially responsible person, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such materials are present, in addition to compensation for natural resource damages, if any.

Clean Air Act

Our operations are subject to the Clean Air Act, its implementing regulations, and analogous state and Canadian statutes and regulations. The EPA regulations under the Clean Air Act contain requirements for the monitoring, reporting, and control of greenhouse gas emissions from stationary sources. For further information, see “—Climate Change” below.

Clean Water Act

Our operations can result in the discharge of pollutants. The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and controls regarding the discharge of pollutants into waters of the U.S. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by applicable federal, state or Canadian authorities. The Oil Pollution Act was enacted in 1990 and amends provisions of the Clean Water Act pertaining to prevention and response to oil spills. Spill prevention control and countermeasure requirements of the Clean Water Act and some state and Canadian laws require containment and similar structures to help prevent contamination of navigable waters in the event of an overflow or release of oil.

EPA Revisions to Ozone National Ambient Air Quality Standard (NAAQS)

As required by the Clean Air Act, EPA establishes National Ambient Air Quality Standards (NAAQS) for how much pollution is permissible and then the states have to adopt rules so their air quality meets the NAAQS. In October

2015, EPA published a rule lowering the ground level ozone NAAQS from 75 ppb to a more stringent 70 ppb standard. This change triggers a process under which EPA will designate the areas of the country that are in or out of attainment with the new NAAQS standard. Then, certain states will have to adopt more stringent air quality regulations to meet the NAAQS standard. These new state rules, which are expected in 2020 or 2021, will likely require the installation of more stringent air pollution controls on newly installed equipment and possibly require retrofitting existing KMI facilities with air pollution controls. Given the nationwide implications of the new rule, it is expected that it will have financial impacts for each of our business units.

Climate Change

Studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases, may be contributing to warming of the Earth's atmosphere. Methane, a primary component of natural gas, and CO_2, which is naturally occurring and also a byproduct of the burning of natural gas, are examples of greenhouse gases. Various laws and regulations exist or are under development that seek to regulate the emission of such greenhouse gases, including the EPA programs to control greenhouse gas emissions and state actions to develop statewide or regional programs. The U.S. Congress has in the past considered legislation to reduce emissions of greenhouse gases.

Beginning in December 2009, EPA published several findings and rulemakings under the Clean Air Act requiring the permitting and reporting of certain greenhouse gases including CO_2 and methane. Our facilities are subject to these requirements. Operational and/or regulatory changes could require additional facilities to comply with greenhouse gas emissions reporting and permitting requirements. Additionally, in June 2016, the EPA published a proposed rule regarding the “Oil and Natural Gas Sector: Emission Standards for New and Modified Sources,” otherwise known as the Proposed New Source Performance Standard (NSPS) Part OOOOa Rule. This rule is the first federal rule under the Clean Air Act to regulate methane as a pollutant and would impose additional pollution control and work practice requirements on applicable KMI facilities.

On October 23, 2015, the EPA published as a final rule the Clean Power Plan, which sets interim and final CO_2 emission performance rates for power generating units that fire coal, oil or natural gas. The final rule is the focus of legislative discussion in the U.S. Congress and litigation in federal court. On February 10, 2016, the U.S. Supreme Court stayed the final rule, effectively suspending the duty to comply with the rule until certain legal challenges are resolved. The ultimate resolution of the final rule’s validity remains uncertain. While we do not operate power plants that would be subject to the Clean Power Plan final rule, it remains unclear what effect the final rule, if it comes into force, might have on the anticipated demand for natural gas, including natural gas that we gather, process, store and transport.

At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already
have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas “cap and trade” programs. Although many of the state-level initiatives have to date been focused on large sources of greenhouse gas emissions, such as electric power plants, it is possible that sources such as our gas-fired compressors and processing plants could become subject to related state regulations. Various states are also proposing or have implemented more strict regulations for greenhouse gases that go beyond the requirements of the EPA. Depending on the particular program, we could be required to conduct monitoring, do additional emissions reporting and/or purchase and surrender emission allowances.

Because our operations, including the compressor stations and processing plants, emit various types of greenhouse gases, primarily methane and CO_2, such new legislation or regulation could increase the costs related to operating and maintaining the facilities. Depending on the particular law, regulation or program, we or our subsidiaries could be required to incur capital expenditures for installing new monitoring equipment of emission controls on the facilities, acquire and surrender allowances for the greenhouse gas emissions, pay taxes related to the greenhouse gas emissions and administer and manage a greenhouse gas emissions program. We are not able at this time to estimate such increased costs; however, as is the case with similarly situated entities in the industry, they could be significant to us. While we may be able to include some or all of such increased costs in the rates charged by our or our subsidiaries’ pipelines, such recovery of costs in all cases is uncertain and may depend on events beyond their control, including the outcome of future rate proceedings before the FERC or other regulatory bodies, and the provisions of any final legislation or other regulations. Any of the foregoing could have an adverse effect on our business, financial position, results of operations and prospects.

Some climatic models indicate that global warming is likely to result in rising sea levels, increased intensity of hurricanes and tropical storms, and increased frequency of extreme precipitation and flooding. We may experience increased insurance premiums and deductibles, or a decrease in available coverage, for our assets in areas subject to severe weather. To the extent these phenomena occur, they could damage our physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone regions. However, the timing and location of these climate change impacts is not known with any certainty and, in any event, these impacts are expected to manifest themselves over a long time horizon. Thus, we are not in a position to say whether the physical impacts of climate change pose a material risk to our business, financial position, results of operations or cash flows.

Because natural gas emits less greenhouse gas emissions per unit of energy than competing fossil fuels, cap-and-trade legislation or EPA regulatory initiatives such as the proposed Clean Power Plan could stimulate demand for natural gas by increasing the relative cost of fuels such as coal and oil. In addition, we anticipate that greenhouse gas regulations will increase demand for carbon sequestration technologies, such as the techniques we have successfully demonstrated in our enhanced oil recovery operations within our CO_2 business segment. However, these positive effects on our markets may be offset if these same regulations also cause the cost of natural gas to increase relative to competing non-fossil fuels. Although we currently cannot predict the magnitude and direction of these impacts, greenhouse gas regulations could have material adverse effects on our business, financial position, results of operations or cash flows.

Department of Homeland Security

The Department of Homeland Security, referred to in this report as the DHS, has regulatory authority over security at certain high-risk chemical facilities. The DHS has promulgated the Chemical Facility Anti-Terrorism Standards and required all high-risk chemical and industrial facilities, including oil and gas facilities, to comply with the regulatory requirements of these standards. This process includes completing security vulnerability assessments, developing site security plans, and implementing protective measures necessary to meet DHS-defined, risk based performance standards. The DHS has not provided final notice to all facilities that it determines to be high risk and subject to the rule; therefore, neither the extent to which our facilities may be subject to coverage by the rules nor the associated costs to comply can currently be determined, but it is possible that such costs could be substantial.

Other

Employees

We employed 11,121 full-time people at December 31, 2016, including approximately 907 full-time hourly personnel at certain terminals and pipelines covered by collective bargaining agreements that expire between 2017 and 2022. We consider relations with our employees to be good.

Most of our employees are employed by us and a limited number of our subsidiaries and provide services to one or more of our business units. The direct costs of compensation, benefits expenses, employer taxes and other employer expenses for these employees are allocated to our subsidiaries. Our human resources department provides the administrative support necessary to implement these payroll and benefits services, and the related administrative costs are allocated to our subsidiaries pursuant to our board-approved expense allocation policy. The effect of these arrangements is that each business unit bears the direct compensation and employee benefits costs of its assigned or partially assigned employees, as the case may be, while also bearing its allocable share of administrative costs.

Properties

We believe that we generally have satisfactory title to the properties we own and use in our businesses, subject to liens for current taxes, liens incident to minor encumbrances, and easements and restrictions, which do not materially detract from the value of such property, the interests in those properties or the use of such properties in our businesses. Our terminals, storage facilities, treating and processing plants, regulator and compressor stations, oil and gas wells, offices and related facilities are located on real property owned or leased by us. In some cases, the real property we lease is on federal, state, provincial or local government land.

We generally do not own the land on which our pipelines are constructed. Instead, we obtain the right to construct and operate the pipelines on other people’s land for a period of time. Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of such property. In many instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. In some cases, not all of the apparent record owners have joined in the right-of-way grants, but in substantially all such cases, signatures of the owners of a majority of the interests have been obtained. Permits have been obtained from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets and state highways, and in some instances, such permits are revocable at the election of the grantor, or, the pipeline may be required to move its facilities at its own expense. Permits also have been obtained from railroad companies to run along or cross over or under lands or rights-of-way, many of which are also revocable at the grantor’s election. Some such permits require annual or other periodic payments. In a few minor cases, property for pipeline purposes was purchased in fee.

(d) Financial Information about Geographic Areas

For geographic information concerning our assets and operations, see Note 16 “Reportable Segments” to our consolidated financial statements.

(e) Available Information

We make available free of charge on or through our internet website, at www.kindermorgan.com, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The information contained on or connected to our internet website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Item 1A. Risk Factors.

You should carefully consider the risks described below, in addition to the other information contained in this document. Realization of any of the following risks could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Risks Related to Operating our Business

Our businesses are dependent on the supply of and demand for the commodities that we handle.

Our pipelines, terminals and other assets and facilities depend in part on continued production of natural gas, oil and other products in the geographic areas that they serve. Our business also depends in part on the levels of demand for oil, natural gas, coal, steel, chemicals and other products in the geographic areas to which our pipelines, terminals, shipping vessels and other facilities deliver or provide service, and the ability and willingness of our shippers and other customers to supply such demand.
Without additions to oil and gas reserves, production will decline over time as reserves are depleted, and production costs may rise. Producers may shut down production at lower product prices or higher production costs, especially where the existing cost of production exceeds other extraction methodologies, such as in the Alberta oil sands. Producers in areas served by us may not be successful in exploring for and developing additional reserves, and our pipelines and related facilities may not be able to maintain existing volumes of throughput. Commodity prices and tax incentives may not remain at levels that encourage producers to explore for and develop additional reserves, produce existing marginal reserves or renew transportation contracts as they expire.

Trends in the business environment, such as declining or sustained low commodity prices, supply disruptions, higher development costs, or high feedstock prices that adversely impact demand, could result in a slowing of supply to our pipelines, terminals and other assets. In addition, changes in the regulatory environment or governmental policies may have an impact on the supply of crude oil, natural gas, coal and other products. Each of these factors impacts our customers shipping through our pipelines or using our terminals, which in turn could impact the prospects of new contracts for transportation, terminaling or other midstream services, or renewals of existing contracts.

Implementation of new regulations or changes to existing regulations affecting the energy industry could reduce production of and/or demand for natural gas, crude oil, refined petroleum products, coal and other hydrocarbons, increase our costs and have a material adverse effect on our results of operations and financial condition. We cannot predict the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce the production of and/or demand for natural gas, crude oil, refined petroleum products and other products we handle.

Our ability to begin and complete construction on expansion and new-build projects may be inhibited by difficulties in obtaining permits and rights-of-way, public opposition, cost overruns, inclement weather and other delays.

We regularly undertake major construction projects to expand our existing assets and to construct new assets. A variety of factors outside of our control, such as difficulties in obtaining permits and rights-of-way or other regulatory approvals that can be exacerbated by public opposition to our projects, have caused, and may continue to cause, delays in our construction projects. Inclement weather, natural disasters and delays in performance by third-party contractors have also resulted in, and may continue to result in, increased costs or delays in construction. Significant cost overruns or delays could have a material adverse effect on our return on investment, results of operations and cash flows, and could result in project cancellations or limit our ability to pursue other growth opportunities.

We do not own substantially all of the land on which our pipelines are located. If we are unable to procure and maintain access to land owned by third parties, our revenue and operating costs, and our ability to complete construction projects, could be adversely affected.

We must obtain and maintain the rights to construct and operate pipelines on other owners' land, including private landowners, railroads, public utilities and others. While our interstate natural gas pipelines have federal eminent domain authority, the availability of eminent domain authority for our other pipelines varies from state to state depending upon the type of pipeline—petroleum liquids, natural gas, CO_2, or crude oil—and the laws of the particular state. In any case, we must compensate landowners for the use of their property, and in eminent domain actions, such compensation may be determined by a court. If we are unable to obtain rights-of-way on acceptable terms, our ability to complete construction projects on time, on budget, or at all, could be adversely affected. In addition, we are subject to the possibility of increased costs under our right-of-way or rental agreements with landowners, primarily through renewals of expiring agreements and rental increases. If we were to lose these rights, our operations could be disrupted or we could be required to relocate the affected pipelines, which could cause a substantial decrease in our revenues and cash flows and increase our costs.

Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us.

We are exposed to the risk of loss in the event of nonperformance by our customers or other counterparties, such as hedging counterparties, joint venture partners and suppliers. Some of these counterparties may be highly leveraged and subject to their own operating, market and regulatory risks, and some are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness.

In the last two years, several of our counterparties defaulted on their obligations to us, and some have filed for bankruptcy protection. For more information regarding the impact to our operating results from customer bankruptcies, see Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations-Results of Operations-Segment Earnings Results-Terminals." We cannot provide any assurance that other financially distressed counterparties will not also default on their obligations to us or file for bankruptcy protection. If a counterparty files for bankruptcy protection, we likely would be unable to collect all, or even a significant portion, of amounts that they owe to us. Additional counterparty defaults and bankruptcy filings could have a material adverse effect on our business, financial position, results of operations or cash flows. Furthermore, in the case of financially distressed customers, such events might force such customers to reduce or curtail their future use of our products and services, which could have a material adverse effect on our results of operations, financial condition, and cash flows.

Our operating results may be adversely affected by unfavorable economic and market conditions.

Economic conditions worldwide have from time to time contributed to slowdowns in several industries, including the oil and gas industry, the steel industry, the coal industry and in specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our products and services. Our operating results in one or more geographic regions also may be affected by uncertain or changing economic conditions within that region. Volatility in commodity prices or changes in markets for a given commodity might also have a negative impact on many of our customers, which in turn could have a negative impact on their ability to meet their obligations to us. See "—Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us." In addition, decreases in the prices of crude oil, NGL and natural gas will have a negative impact on our operating results and cash flow. See "—The volatility of oil and natural gas prices could have a material adverse effect on our CO_2 business segment and businesses within our Natural Gas Pipeline and Products Pipelines business segments."

If global economic and market conditions (including volatility in commodity markets), or economic conditions in the U.S. or other key markets, remain uncertain or persist, spread or deteriorate further, we may experience material impacts on our business, financial condition and results of operations.

The acquisition of additional businesses and assets is part of our growth strategy. We may experience difficulties integrating new properties and businesses, and we may be unable to achieve the benefits we expect from any future acquisitions.

Part of our business strategy includes acquiring additional businesses and assets. If we do not successfully integrate acquisitions, we may not realize anticipated operating advantages and cost savings. Integration of acquired companies or assets involves a number of risks, including (i) demands on management related to the increase in our size; (ii) the diversion of management's attention from the management of daily operations; (iii) difficulties in implementing or unanticipated costs of accounting, budgeting, reporting and other systems; and (iv) difficulties in the retention and assimilation of necessary employees.

We may not be able to maintain the levels of operating efficiency that acquired companies have achieved or might achieve separately. Successful integration of each acquisition will depend upon our ability to manage those operations and to eliminate redundant and excess costs. Difficulties in integration may be magnified if we make multiple acquisitions over a relatively short period of time. Because of difficulties in combining and expanding operations, we may not be able to achieve the cost savings and other size-related benefits that we hoped to achieve after these acquisitions, which would harm our financial condition and results of operations.

We face competition from other pipelines and other forms of transportation into the areas we serve as well as with respect to the supply for our pipeline systems.

Any current or future pipeline system or other form of transportation that delivers crude oil, petroleum products or natural gas into the areas that our pipelines serve could offer transportation services that are more desirable to shippers than those we provide because of price, location, facilities or other factors. To the extent that an excess of supply into these areas is created and persists, our ability to re-contract for expiring transportation capacity at favorable rates or otherwise to retain existing customers could be impaired. We also could experience competition for the supply of petroleum products or natural gas from both existing and proposed pipeline systems; for example, several pipelines access many of the same areas of supply as our pipeline systems and transport to destinations not served by us.

Commodity transportation and storage activities involve numerous risks that may result in accidents or otherwise adversely affect our operations.

There are a variety of hazards and operating risks inherent to transportation and storage of crude oil, natural gas, refined petroleum products, CO_2, coal, chemicals and other products -such as leaks, releases, explosions, mechanical problems and damage caused by third parties. Additional risks to vessels include adverse sea conditions, capsizing, grounding and navigation errors. These risks could result in serious injury and loss of human life, significant damage to property and natural resources, environmental pollution and impairment of operations, any of which also could result in substantial financial losses. For pipeline and storage assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks may be greater. Incidents that cause an interruption of service, such as when unrelated third party construction damages a pipeline or a newly completed expansion experiences a weld failure, may negatively impact our revenues and cash flows while the affected asset is temporarily out of service. In addition, losses in excess of our insurance coverage could have a material adverse effect on our business, financial condition and results of operations.

The volatility of oil, NGL and natural gas prices could adversely affect our CO_2 business segment and businesses within our Natural Gas Pipelines and Products Pipelines business segments.

The revenues, cash flows, profitability and future growth of some of our businesses depend to a large degree on prevailing oil, natural gas and NGL prices. Our CO_2 business segment (and the carrying value of its oil, NGL and natural gas producing properties) and certain midstream businesses within our Natural Gas Pipelines segment depend to a large degree, and certain businesses within our Product Pipelines segment depend to a lesser degree, on prevailing oil, NGL and natural gas prices. For 2017, we estimate that every $1 change in the average WTI crude oil price per barrel would impact our distributable cash flow by approximately $6 million, each $0.10 per MMBtu change in the average price of natural gas would impact distributable cash flow by approximately $1 million and each 1% change in the ratio of the weighted-average NGL price per barrel to the WTI crude oil price per barrel would impact distributable cash flow by approximately $3 million.

Prices for oil, NGL and natural gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil, NGL and natural gas, uncertainties within the market and a variety of other factors beyond our control. These factors include, among other things (i) weather conditions and events such as hurricanes in the U.S.; (ii) the condition of the U.S. economy; (iii) the activities of the Organization of Petroleum Exporting Countries; (iv) governmental regulation; (v) political instability in the Middle East and elsewhere; (vi) the foreign supply of and demand for oil and natural gas; (vii) the price of foreign imports; and (viii) the availability of alternative fuel sources. We use hedging arrangements to partially mitigate our exposure to commodity prices, but these arrangements also are subject to inherent risks. Please read "—Our use of hedging arrangements does not eliminate our exposure to commodity price risks and could result in financial losses or volatility in our income."

A sharp decline in the prices of oil, NGL or natural gas, or a prolonged unfavorable price environment, would result in a commensurate reduction in our revenues, income and cash flows from our businesses that produce, process, or purchase and sell oil, NGL, or natural gas, and could have a material adverse effect on the carrying value of our CO_2 business segment's proved reserves. If prices fall substantially or remain low for a sustained period and we are not sufficiently protected through hedging arrangements, we may be unable to realize a profit from these businesses and would operate at a loss.

In recent decades, there have been periods of both worldwide overproduction and underproduction of hydrocarbons and periods of both increased and relaxed energy conservation efforts. Such conditions have resulted in periods of excess supply of, and reduced demand for, crude oil on a worldwide basis and for natural gas on a domestic basis. These periods have been followed by periods of short supply of, and increased demand for, crude oil and natural gas. The excess or short supply of crude oil or natural gas has placed pressures on prices and has resulted in dramatic price fluctuations even during relatively short periods of seasonal market demand. These fluctuations impact the accuracy of assumptions used in our budgeting process. For more information about our energy and commodity market risk, see Item 7A "Quantitative and Qualitative Disclosures About Market Risk-Energy Commodity Market Risk."

The future success of our oil and gas development and production operations depends in part upon our ability to develop additional oil and gas reserves that are economically recoverable.

The rate of production from oil and natural gas properties declines as reserves are depleted. Without successful development activities, the reserves, revenues and cash flows of the oil and gas producing assets within our CO_2 business segment will decline. We may not be able to develop or acquire additional reserves at an acceptable cost or have necessary financing for these activities in the future. Additionally, if we do not realize production volumes greater than, or equal to, our hedged volumes, we may suffer financial losses not offset by physical transactions.

The development of oil and gas properties involves risks that may result in a total loss of investment.

The business of developing and operating oil and gas properties involves a high degree of business and financial risk that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Acquisition and development decisions generally are based on subjective judgments and assumptions that, while they may be reasonable, are by their nature speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, the successful completion of a well does not ensure a profitable return on the investment. A variety of geological, operational and market-related factors, including, but not limited to, unusual or unexpected geological formations, pressures, equipment failures or accidents, fires, explosions, blowouts, cratering, pollution and other environmental risks, shortages or delays in the availability of drilling rigs and the delivery of equipment, loss of circulation of drilling fluids or other conditions, may substantially delay or prevent completion of any well or otherwise prevent a property or well from being profitable. A productive well may become uneconomic in the event water or other deleterious substances are encountered, which impair or prevent the production of oil and/or gas from the well. In addition, production from any well may be unmarketable if it is contaminated with water or other deleterious substances.

Our use of hedging arrangements does not eliminate our exposure to commodity price risks and could result in financial losses or volatility in our income.

We engage in hedging arrangements to reduce our exposure to fluctuations in the prices of oil, NGL and natural gas. These hedging arrangements expose us to risk of financial loss in some circumstances, including when production is less than expected, when the counterparty to the hedging contract defaults on its contract obligations, or when there is a change in the expected differential between the underlying price in the hedging agreement and the actual price received. In addition, these hedging arrangements may limit the benefit we would otherwise receive from increases in prices for oil and natural gas.

The markets for instruments we use to hedge our commodity price exposure generally reflect then-prevailing conditions in the underlying commodity markets. As our existing hedges expire, we will seek to replace them with new hedging arrangements. To the extent underlying market conditions are unfavorable, new hedging arrangements available to us will reflect such unfavorable conditions.

The accounting standards regarding hedge accounting are very complex, and even when we engage in hedging transactions (for example, to mitigate our exposure to fluctuations in commodity prices or currency exchange rates or to balance our exposure to fixed and variable interest rates) that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our consolidated financial statements may reflect some volatility due to these hedges, even when there is no underlying economic impact at the dates of those statements. In addition, it is not possible for us to engage in hedging transactions that eliminate our exposure to commodity prices. Our consolidated financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge. For more information about our hedging activities, see Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Critical Accounting Policies and Estimates-Hedging Activities” and Note 13 “Risk Management” to our consolidated financial statements.

Terrorist attacks or “cyber security” events, or the threat of them, may adversely affect our business or harm our business reputation.

The U.S. government has issued public warnings that indicate that pipelines and other infrastructure assets might be specific targets of terrorist organizations or “cyber security” events. These potential targets might include our pipeline systems, terminals, processing plants or operating systems. A cyber security event could affect our ability to operate or control our facilities or disrupt our operations; also, customer information could be stolen. The occurrence of one of these events could cause a substantial decrease in revenues and cash flows, increased costs to respond or other financial loss, damage to our reputation, increased regulation or litigation or inaccurate information reported from our operations. There is no assurance that adequate cyber sabotage and terrorism insurance will be available at rates we believe are reasonable in the near future. These developments may subject our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations and financial condition or harm our business reputation.

Hurricanes, earthquakes and other natural disasters could have an adverse effect on our business, financial condition and results of operations.

Some of our pipelines, terminals and other assets are located in, and our shipping vessels operate in, areas that are susceptible to hurricanes, earthquakes and other natural disasters. These natural disasters could potentially damage or destroy our assets and disrupt the supply of the products we transport. Natural disasters can similarly affect the facilities of our customers. In either case, losses could exceed our insurance coverage and our business, financial condition and results of operations could be adversely affected, perhaps materially.

Our business requires the retention and recruitment of a skilled workforce, and difficulties recruiting and retaining our workforce could result in a failure to implement our business plans.

Our operations and management require the retention and recruitment of a skilled workforce, including engineers, technical personnel and other professionals. We and our affiliates compete with other companies in the energy industry for this skilled workforce. In addition, many of our current employees are retirement eligible and have significant institutional knowledge that must be transferred to other employees. If we are unable to (i) retain current employees; (ii) successfully complete the knowledge transfer; and/or (iii) recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased allocated costs to retain and recruit these professionals.

If we are unable to retain our executive chairman or other executive officers, our ability to execute our business strategy, including our growth strategy, may be hindered.

Our success depends in part on the performance of and our ability to retain our executive officers, particularly Richard D. Kinder, our Executive Chairman and one of our founders, and Steve Kean, our President and Chief Executive Officer. Along with the other members of our senior management, Mr. Kinder and Mr. Kean have been responsible for developing and executing our growth strategy. If we are not successful in retaining Mr. Kinder, Mr. Kean or our other executive officers, or replacing them, our business, financial condition or results of operations could be adversely affected. We do not maintain key personnel insurance.

Our Kinder Morgan Canada and Terminals segments are subject to U.S. dollar/Canadian dollar exchange rate fluctuations.

We are a U.S. dollar reporting company. As a result of the operations of our Kinder Morgan Canada business segments, a portion of our consolidated assets, liabilities, revenues, cash flows and expenses are denominated in Canadian dollars. Fluctuations in the exchange rate between U.S. and Canadian dollars could expose us to reductions in the U.S. dollar value of our earnings and cash flows and a reduction in our stockholders' equity under applicable accounting rules.

Risks Related to Financing Our Business

Our substantial debt could adversely affect our financial health and make us more vulnerable to adverse economic conditions.

As of December 31, 2016, we had approximately $39 billion of consolidated debt (excluding debt fair value adjustments). Additionally, we and substantially all of our wholly owned subsidiaries are parties to a cross guarantee agreement under which each party to the agreement unconditionally guarantees the indebtedness of each other party, which means that we are liable for the debt of each of such subsidiaries. This level of consolidated debt and the cross guarantee agreement could have important consequences, such as (i) limiting our ability to obtain additional financing to fund our working capital, capital expenditures, debt service requirements or potential growth, or for other purposes; (ii) increasing the cost of our future borrowings; (iii) limiting our ability to use operating cash flow in other areas of our business or to pay dividends because we must dedicate a substantial portion of these funds to make payments on our debt; (iv) placing us at a competitive disadvantage compared to competitors with less debt; and (v) increasing our vulnerability to adverse economic and industry conditions.

Our ability to service our consolidated debt, and our ability to meet our consolidated leverage targets, will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond our control. If our consolidated cash flow is not sufficient to service our consolidated debt, and any future indebtedness that we incur, we will be forced to take actions such as reducing dividends, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may also take such actions to reduce our indebtedness if we determine that our earnings (or consolidated earnings before interest, taxes, depreciation and amortization, or EBITDA, as calculated in accordance with our revolving credit facility) may not be sufficient to meet our consolidated leverage targets, or to comply with consolidated leverage ratios required under certain of our debt agreements. We may not be able to effect any of these actions on satisfactory terms or at all. For more information about our debt, see Note 8 “Debt” to our consolidated financial statements.

Our business, financial condition and operating results may be affected adversely by increased costs of capital or a reduction in the availability of credit.

Adverse changes to the availability, terms and cost of capital, interest rates or our credit ratings (which would have a corresponding impact on the credit ratings of our subsidiaries that are party to the cross guarantee) could cause our cost of doing business to increase by limiting our access to capital, including our ability to refinance maturities of existing indebtedness on similar terms, which could in turn limit our ability to pursue acquisition or expansion opportunities and reduce our cash flows. Our credit ratings may be impacted by our leverage, liquidity, credit profile and potential transactions. Although the ratings from credit agencies are not recommendations to buy, sell or hold our securities, our credit ratings will generally affect the market value of our and our subsidiaries’ debt securities and the terms available to us for future issuances of debt securities.

Also, disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations on favorable terms. A significant reduction in the availability of credit could materially and adversely affect our business, financial condition and results of operations.

Our acquisition strategy and growth capital expenditures may require access to external capital. Limitations on our access to external financing sources could impair our ability to grow.

We have limited amounts of internally generated cash flows to fund acquisitions and growth capital expenditures. We may have to rely on external financing sources, including commercial borrowings and issuances of debt and equity securities, to fund our acquisitions and growth capital expenditures. Limitations on our access to external financing sources, whether due to tightened capital markets, more expensive capital or otherwise, could impair our ability to execute our growth strategy.

Our large amount of variable rate debt makes us vulnerable to increases in interest rates.

As of December 31, 2016, approximately $11 billion of our approximately $39 billion of consolidated debt (excluding debt fair value adjustments) was subject to variable interest rates, either as short-term or long-term variable-rate debt obligations, or as long-term fixed-rate debt effectively converted to variable rates through the use of interest rate swaps. Should interest rates increase, the amount of cash required to service this debt would increase, and our earnings and cash flows could be adversely affected. For more information about our interest rate risk, see Item 7A "Quantitative and Qualitative Disclosures About Market Risk-Interest Rate Risk."

Our debt instruments may limit our financial flexibility and increase our financing costs.

The instruments governing our debt contain restrictive covenants that may prevent us from engaging in certain transactions that we deem beneficial and that may be beneficial to us. Some of the agreements governing our debt generally require us to comply with various affirmative and negative covenants, including the maintenance of certain financial ratios and restrictions on (i) incurring additional debt; (ii) entering into mergers, consolidations and sales of assets; (iii) granting liens; and (iv) entering into sale-leaseback transactions. The instruments governing any future debt may contain similar or more restrictive restrictions. Our ability to respond to changes in business and economic conditions and to obtain additional financing, if needed, may be restricted.

Risks Related to Ownership of Our Capital Stock

The guidance we provide for our anticipated dividends is based on estimates. Circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business.

We disclose in this report and elsewhere the expected cash dividends on our common stock and on our preferred stock (or depositary shares). This reflects our current judgment, but as with any estimate, it may be affected by inaccurate assumptions and other risks and uncertainties, many of which are beyond our control. See “Information Regarding Forward-Looking Statements.” If we elect to pay dividends at the anticipated level and that action would leave us with insufficient cash to take timely advantage of growth opportunities (including through acquisitions), to meet any large unanticipated liquidity requirements, to fund our operations, to maintain our leverage metrics or otherwise to address properly our business prospects, our business could be harmed.

Conversely, a decision to address such needs might lead to the payment of dividends below the anticipated levels. As events present themselves or become reasonably foreseeable, our board of directors, which determines our business strategy and our dividends, may decide to address those matters by reducing our anticipated dividends. Alternatively, because nothing in our governing documents or credit agreements prohibits us from borrowing to pay dividends, we could choose to incur debt to enable us to pay our anticipated dividends. This would add to our substantial debt discussed above under “—Risks Related to Financing Our Business—Our substantial debt could adversely affect our financial health and make us more vulnerable to adverse economic conditions.”

Our certificate of incorporation restricts the ownership of our common stock by non-U.S. citizens within the meaning of the Jones Act. These restrictions may affect the liquidity of our common stock and may result in non-U.S. citizens being required to sell their shares at a loss.

The Jones Act requires, among other things, that at least 75% of our common stock be owned at all times by U.S. citizens, as defined under the Jones Act, in order for us to own and operate vessels in the U.S. coastwise trade. As a safeguard to help us maintain our status as a U.S. citizen, our certificate of incorporation provides that, if the number of shares of our common stock owned by non-U.S. citizens exceeds 22%, we have the ability to redeem shares owned by non-U.S. citizens to reduce the percentage of shares owned by non-U.S. citizens to 22%. These redemption provisions may adversely impact the marketability of our common stock, particularly in markets outside of the U.S. Further, stockholders would not have control over the timing of such redemption, and may be subject to redemption at a time when the market price or timing of the redemption is disadvantageous. In addition, the redemption provisions might have the effect of impeding or discouraging a merger, tender offer or proxy contest by a non-U.S. citizen, even if it were favorable to the interests of some or all of our stockholders.

Risks Related to Regulation

New laws, policies, regulations, rulemaking and oversight, as well as changes to those currently in effect, could adversely impact our earnings, cash flows and operations.

Our assets and operations are subject to regulation and oversight by federal, state, provincial and local regulatory authorities. Legislative changes, as well as regulatory actions taken by these agencies, have the potential to adversely affect our profitability. In addition, a certain degree of regulatory uncertainty is created by the recent change in U.S. presidential administrations. It remains unclear specifically what the new administration may do with respect to future policies and regulations that may affect us. Regulation affects almost every part of our business and extends to such matters as (i) federal, state, provincial and local taxation; (ii) rates (which include tax, reservation, commodity, surcharges, fuel and gas lost and unaccounted for), operating terms and conditions of service; (iii) the types of services we may offer to our customers; (iv) the contracts for service entered into with our customers; (v) the certification and construction of new facilities; (vi) the integrity, safety and security of facilities and operations; (vii) the acquisition of other businesses; (viii) the acquisition, extension, disposition or abandonment of services or facilities; (ix) reporting and information posting requirements; (x) the maintenance of accounts and records; and (xi) relationships with affiliated companies involved in various aspects of the natural gas and energy businesses.

Should we fail to comply with any applicable statutes, rules, regulations, and orders of regulatory authorities, we could be subject to substantial penalties and fines and potential loss of government contracts. Furthermore, new laws, regulations or policy changes sometimes arise from unexpected sources. New laws or regulations, or different interpretations of existing laws or regulations, including unexpected policy changes, applicable to our income, operations, assets or another aspect of our business, could have a material adverse impact on our earnings, cash flow, financial condition and results of operations. For more information, see Items 1 and 2 “Business and Properties-(c) Narrative Description of Business-Regulation.”

The FERC, the CPUC, or the NEB may establish pipeline tariff rates that have a negative impact on us. In addition, the FERC, the CPUC, the NEB, or our customers could file complaints challenging the tariff rates charged by our pipelines, and a successful complaint could have an adverse impact on us.

The profitability of our regulated pipelines is influenced by fluctuations in costs and our ability to recover any increases in our costs in the rates charged to our shippers. To the extent that our costs increase in an amount greater than what we are permitted by the FERC, the CPUC, or the NEB to recover in our rates, or to the extent that there is a lag before we can file for and obtain rate increases, such events can have a negative impact upon our operating results.

Our existing rates may also be challenged by complaint. Regulators and shippers on our pipelines have rights to challenge, and have challenged, the rates we charge under certain circumstances prescribed by applicable regulations. Some shippers on our pipelines have filed complaints with the regulators that seek substantial refunds for alleged overcharges during the years in question and prospective reductions in the tariff rates. Further, the FERC may continue to initiate investigations to determine whether interstate natural gas pipelines have over-collected on rates charged to shippers. We may face challenges, similar to those described in Note 17 to our consolidated financial statements, to the rates we charge on our pipelines. Any successful challenge to our rates could materially adversely affect our future earnings, cash flows and financial condition.

Environmental, health and safety laws and regulations could expose us to significant costs and liabilities.

Our operations are subject to federal, state, provincial and local laws, regulations and potential liabilities arising under or relating to the protection or preservation of the environment, natural resources and human health and safety. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with various environmental registrations, licenses, permits, inspections and other approvals. Liability under such laws and regulations may be incurred without regard to fault under CERCLA, the Resource Conservation and Recovery Act, the Federal Clean Water Act or analogous state or provincial laws for the remediation of contaminated areas. Private parties, including the owners of properties through which our pipelines pass, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with such laws and regulations or for personal injury or property damage. Our insurance may not cover all environmental risks and costs and/or may not provide sufficient coverage in the event an environmental claim is made against us.

Failure to comply with these laws and regulations also may expose us to civil, criminal and administrative fines, penalties and/or interruptions in our operations that could influence our business, financial position, results of operations and prospects. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines, shipping vessels or storage or other facilities, we may experience significant operational disruptions and we may have to pay a significant amount to clean up or otherwise respond to the leak, release or spill, pay for government penalties, address natural resource damage, compensate for human exposure or property damage, install costly pollution control equipment or undertake a combination of these and other measures. The resulting costs and liabilities could materially and negatively affect our earnings and cash flows. In addition, emission controls required under the Federal Clean Air Act and other similar federal, state and provincial laws could require significant capital expenditures at our facilities.

We own and/or operate numerous properties that have been used for many years in connection with our business activities. While we believe we have utilized operating, handling, and disposal practices that were consistent with industry practices at the time, hydrocarbons or other hazardous substances may have been released at or from properties owned, operated or used by us or our predecessors, or at or from properties where our or our predecessors' wastes have been taken for disposal. In addition, many of these properties have been owned and/or operated by third parties whose management, handling and disposal of hydrocarbons or other hazardous substances were not under our control. These properties and the hazardous substances released and wastes disposed on them may be subject to laws in the U.S. such as CERCLA, which impose joint and several liability without regard to fault or the legality of the original conduct. Under the regulatory schemes of the various Canadian provinces, such as British Columbia's Environmental Management Act, Canada has similar laws with respect to properties owned, operated or used by us or our predecessors. Under such laws and implementing regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including contamination caused by prior owners or operators. Imposition of such liability schemes could have a material adverse impact on our operations and financial position.

Further, we cannot ensure that such existing laws and regulations will not be revised or that new laws or regulations will not be adopted or become applicable to us. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects. For more information, see Items 1 and 2 "Business and Properties-(c) Narrative Description of Business-Environmental Matters."

Increased regulatory requirements relating to the integrity of our pipelines may require us to incur significant capital and operating expense outlays to comply.

We are subject to extensive laws and regulations related to pipeline integrity. There are, for example, federal guidelines issued by the DOT for pipeline companies in the areas of testing, education, training and communication. The ultimate costs of compliance with the integrity management rules are difficult to predict. The majority of compliance costs relate to pipeline integrity testing and repairs. Technological advances in in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipeline determined to be located in "High Consequence Areas" can have a significant impact on integrity testing and repair costs. We plan to continue our integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by the DOT rules. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Further, additional laws and regulations that may be enacted in the future or a new interpretation of existing laws and regulations could significantly increase the amount of these expenditures. There can be no assurance as to the amount or timing of future expenditures for pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not deemed by regulators to be fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects.

Climate change regulation at the federal, state, provincial or regional levels could result in significantly increased operating and capital costs for us and could reduce demand for our products and services.

Various laws and regulations exist or are under development that seek to regulate the emission of greenhouse gases such as methane and CO_2, including the EPA programs to control greenhouse gas emissions and state actions to develop statewide or regional programs. Existing EPA regulations require us to report greenhouse gas emissions in the U.S. from sources such as our larger natural gas compressor stations, fractionated NGL, and production of naturally occurring CO_2 (for example, from our McElmo Dome CO_2 field), even when such production is not emitted to the atmosphere. Proposed approaches to further regulate greenhouse gas emissions include establishing greenhouse gas "cap and trade" programs, increased efficiency standards, and incentives or mandates for pollution reduction, use of renewable energy sources, or use of alternative fuels with lower carbon content. For more information about climate change regulation, see Items 1 and 2 "Business and Properties-(c) Narrative Description of Business-Environmental Matters-Climate Change."

Adoption of any such laws or regulations could increase our costs to operate and maintain our facilities and could require us to install new emission controls on our facilities, acquire allowances for our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program, and such increased costs could be significant. Recovery of such increased costs from our customers is uncertain in all cases and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC. Such laws or regulations could also lead to reduced demand for hydrocarbon products that are deemed to contribute to greenhouse gases, or restrictions on their use, which in turn could adversely affect demand for our products and services.

Finally, some climatic models indicate that global warming is likely to result in rising sea levels and increased frequency and severity of weather events, which may lead to higher insurance costs, or a decrease in available coverage, for our assets in areas subject to severe weather. To the extent these phenomena occur, they could damage our physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone regions.

Any of the foregoing could have adverse effects on our business, financial position, results of operations or cash flows.

Increased regulation of exploration and production activities, including hydraulic fracturing, could result in reductions or delays in drilling and completing new oil and natural gas wells, as well as reductions in production from existing wells, which could adversely impact the volumes of natural gas transported on our natural gas pipelines and our own oil and gas development and production activities.

We gather, process or transport crude oil, natural gas or NGL from several areas in which the use of hydraulic fracturing is prevalent. Oil and gas development and production activities are subject to numerous federal, state, provincial and local laws and regulations relating to environmental quality and pollution control. The oil and gas industry is increasingly relying on supplies of hydrocarbons from unconventional sources, such as shale, tight sands and coal bed methane. The extraction of hydrocarbons from these sources frequently requires hydraulic fracturing. Hydraulic fracturing involves the pressurized injection of water, sand, and chemicals into the geologic formation to stimulate gas production and is a commonly used stimulation process employed by oil and gas exploration and production operators in the completion of certain oil and gas wells. There have been initiatives at the federal and state levels to regulate or otherwise restrict the use of hydraulic fracturing. Adoption of legislation or regulations placing restrictions on hydraulic fracturing activities could impose operational delays, increased operating costs and additional regulatory burdens on exploration and production operators, which could reduce their production of crude oil, natural gas or NGL and, in turn, adversely affect our revenues, cash flows and results of operations by decreasing the volumes of these commodities that we handle.

In addition, many states are promulgating stricter requirements not only for wells but also compressor stations and other facilities in the oil and gas industry sector. These laws and regulations increase the costs of these activities and may prevent or delay the commencement or continuance of a given operation. Specifically, these activities are subject to laws and regulations regarding the acquisition of permits before drilling, restrictions on drilling activities and location, emissions into the environment, water discharges, transportation of hazardous materials, and storage and disposition of wastes. In addition, legislation has been enacted that requires well and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. These laws and regulations may adversely affect our oil and gas development and production activities.

Derivatives regulation could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the OTC derivatives market and entities that participate in that market. In December 2016, the CFTC re-proposed new rules pursuant to the Dodd-Frank Act that would institute broad new aggregate position limits for OTC swaps and futures and options traded on regulated exchanges. As the law favors exchange trading and clearing, the Dodd-Frank Act also may require us to move certain derivatives transactions to exchanges where no trade credit is provided. The Dodd-Frank Act, related regulations and the reduction in competition due to derivatives industry consolidation have (i) significantly increased the cost of derivative contracts (including those requirements to post collateral, which could adversely affect our available liquidity); (ii) reduced the availability of derivatives to protect against risks we encounter; and (iii) reduced the liquidity of energy related derivatives.

If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues and cash flows could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our financial condition and results of operations.

The Jones Act includes restrictions on ownership by non-U.S. citizens of our U.S. point to point maritime shipping vessels, and failure to comply with the Jones Act, or changes to or a repeal of the Jones Act, could limit our ability to operate our vessels in the U.S. coastwise trade, result in the forfeiture of our vessels or otherwise adversely impact our earnings, cash flows and operations.

We are subject to the Jones Act, which generally restricts U.S. point-to-point maritime shipping to vessels operating under the U.S. flag, built in the U.S., owned and operated by U.S.-organized companies that are controlled and at least 75% owned by U.S. citizens and manned by predominately U.S. crews. Our business would be adversely affected if we fail to comply with the Jones Act provisions on coastwise trade. If we do not comply with any of these requirements, we would be prohibited from operating our vessels in the U.S. coastwise trade and, under certain circumstances, we could be deemed to have undertaken an unapproved transfer to non-U.S. citizens that could result in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of vessels. Our business could be adversely affected if the Jones Act were to be modified or repealed so as to permit foreign competition that is not subject to the same U.S. government imposed burdens.

Item 1B. Unresolved Staff Comments.

None.

Item 3. Legal Proceedings.

See Note 17 “Litigation, Environmental and Other Contingencies” to our consolidated financial statements.

Item 4. Mine Safety Disclosures.

The information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is in exhibit 95.1 to this annual report.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Our Class P common stock is listed for trading on the NYSE under the symbol "KMI." The high and low sale prices per Class P share as reported on the NYSE and the dividends declared per share by period for 2016, 2015 and 2014, are provided below.

	Price Range		Declared Cash Dividends(a)
	Low	High	
2016			
First Quarter	$11.20	$19.32	$ 0.125
Second Quarter	16.63	19.40	0.125
Third Quarter	17.95	23.20	0.125
Fourth Quarter	19.43	23.36	0.125
2015			
First Quarter	$39.45	$42.93	$ 0.48
Second Quarter	38.33	44.71	0.49
Third Quarter	25.81	38.58	0.51
Fourth Quarter	14.22	32.89	0.125
2014			
First Quarter	$30.81	$36.45	$ 0.42
Second Quarter	32.10	36.50	0.43
Third Quarter	35.20	42.49	0.44
Fourth Quarter	33.25	43.18	0.45

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(a) Dividend information is for dividends declared with respect to that quarter. Generally, our declared dividends for our Class P common stock are paid on or about the 15th day of each February, May, August and November.

As of February 9, 2017, we had 12,386 holders of our Class P common stock, which does not include beneficial owners whose shares are held by a nominee, such as a broker or bank.

For information on our equity compensation plans, see Note 10 "Share-based Compensation and Employee Benefits—Share-based Compensation" to our consolidated financial statements.

On June 12, 2015, we announced that our board of directors had approved a warrant repurchase program authorizing us to repurchase up to $100 million of warrants. As of December 31, 2016, we had approximately $90 million of remaining approved funds under this warrant repurchase program. The warrants expire on May 25, 2017.

Item 6. Selected Financial Data.

The following table sets forth, for the periods and at the dates indicated, our summary historical financial data. The table is derived from our consolidated financial statements and notes thereto, and should be read in conjunction with those audited financial statements. See also Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in this report for more information.

Five-Year Review
Kinder Morgan, Inc. and Subsidiaries

	As of or for the Year Ended December 31,				
	2016	2015	2014	2013	2012
	(In millions, except per share amounts)				
Income and Cash Flow Data:					
Revenues	$13,058	$14,403	$16,226	$14,070	$9,973
Operating income	3,572	2,447	4,448	3,990	2,593
Earnings from equity investments	497	414	406	327	153
Income from continuing operations	721	208	2,443	2,696	1,204
Loss from discontinued operations, net of tax	—	—	—	(4)	(777)
Net income	721	208	2,443	2,692	427
Net income attributable to Kinder Morgan, Inc.	708	253	1,026	1,193	315
Net income available to common stockholders	552	227	1,026	1,193	315
Class P Shares					
Basic and Diluted Earnings Per Common Share From Continuing Operations	$0.25	$0.10	$0.89	$1.15	$0.56
Basic and Diluted Loss Per Common Share From Discontinued Operations	—	—	—	—	(0.21)
Total Basic and Diluted Earnings Per Common Share	$0.25	$0.10	$0.89	$1.15	$0.35
Class A Shares					
Basic and Diluted Earnings Per Common Share From Continuing Operations					$0.47
Basic and Diluted Loss Per Common Share From Discontinued Operations					(0.21)
Total Basic and Diluted Earnings Per Common Share					$0.26
Basic Weighted Average Common Shares Outstanding:					
Class P shares	2,230	2,187	1,137	1,036	461
Class A shares					446
Diluted Weighted Average Common Shares Outstanding:					
Class P shares	2,230	2,193	1,137	1,036	908
Class A shares					446
Dividends per common share declared for the period(a)	$0.50	$1.605	$1.74	$1.60	$1.40
Dividends per common share paid in the period(a)	0.50	1.93	1.70	1.56	1.34
Balance Sheet Data (at end of period):					
Property, plant and equipment, net	$38,705	$40,547	$38,564	$35,847	$30,996
Total assets	80,305	84,104	83,049	75,071	68,133
Long-term debt(b)	36,205	40,732	38,312	31,910	29,409

(a) Dividends for the fourth quarter of each year are declared and paid during the first quarter of the following year.
(b) Excludes debt fair value adjustments. Increases to long-term debt for debt fair value adjustments totaled $1,149 million, $1,674 million, $1,785 million, $1,863 million and $2,479 million as of December 31, 2016, 2015, 2014,

2013 and 2012, respectively.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the notes thereto. We prepared our consolidated financial statements in accordance with GAAP. Additional sections in this report which should be helpful to the reading of our discussion and analysis include the following: (i) a description of our business strategy found in Items 1 and 2 "Business and Properties—(c) Narrative Description of Business—Business Strategy;" (ii) a description of developments during 2016, found in Items 1 and 2 "Business and Properties—(a) General Development of Business—Recent Developments;" and (iii) a description of risk factors affecting us and our business, found in Item 1A "Risk Factors."

Inasmuch as the discussion below and the other sections to which we have referred you pertain to management's comments on financial resources, capital spending, our business strategy and the outlook for our business, such discussions contain forward-looking statements. These forward-looking statements reflect the expectations, beliefs, plans and objectives of management about future financial performance and assumptions underlying management's judgment concerning the matters discussed, and accordingly, involve estimates, assumptions, judgments and uncertainties. Our actual results could differ materially from those discussed in the forward-looking statements. Factors that could cause or contribute to any differences include, but are not limited to, those discussed below and elsewhere in this report, particularly in Item 1A "Risk Factors" and at the beginning of this report in "Information Regarding Forward-Looking Statements."

General

Our business model, through our ownership and operation of energy related assets, is built to support two principal objectives:

- helping customers by providing safe and reliable natural gas, liquids products and bulk commodity transportation, storage and distribution; and

- creating long-term value for our shareholders.

To achieve these objectives, we focus on providing fee-based services to customers from a business portfolio consisting of energy-related pipelines, natural gas storage, processing and treating facilities, and bulk and liquids terminal facilities. We also produce and sell crude oil. Our reportable business segments are based on the way our management organizes our enterprise, and each of our business segments represents a component of our enterprise that engages in a separate business activity and for which discrete financial information is available.

Our reportable business segments are:

- Natural Gas Pipelines—the ownership and operation of (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas and crude oil gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG facilities;

- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium for recovering crude oil from mature oil fields to increase production; (ii) ownership interests in and/or operation of oil fields and gas processing plants in West Texas; and (iii) the ownership and operation of a crude oil pipeline system in West Texas;

- Terminals—the ownership and/or operation of (i) liquids and bulk terminal facilities located throughout the U.S. and portions of Canada that transload and store refined petroleum products, crude oil, chemicals, and ethanol and bulk products, including coal, petroleum coke, fertilizer, steel and ores and (ii) Jones Act tankers;

- Products Pipelines—the ownership and operation of refined petroleum products, NGL and crude oil and condensate pipelines that primarily deliver, among other products, gasoline, diesel and jet fuel, propane, crude oil and condensate to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities; and

- Kinder Morgan Canada—the ownership and operation of the Trans Mountain pipeline system that transports crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia, Canada and the state of Washington, plus the Jet Fuel aviation turbine fuel pipeline that serves the Vancouver (Canada) International Airport.

As an energy infrastructure owner and operator in multiple facets of the various U.S. and Canadian energy industries and markets, we examine a number of variables and factors on a routine basis to evaluate our current performance and our prospects for the future.

With respect to our interstate natural gas pipelines, related storage facilities and LNG terminals, the revenues from these assets are primarily received under contracts with terms that are fixed for various and extended periods of time. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate risk of reduced volumes and prices by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. These long-term contracts are typically structured with a fixed-fee reserving the right to transport or store natural gas and specify that we receive the majority of our fee for making the capacity available, whether or not the customer actually chooses to utilize the capacity. Similarly, the Texas Intrastate Natural Gas Pipeline operations, currently derives approximately 77% of its sales and transport margins from long-term transport and sales contracts. As contracts expire, we have additional exposure to the longer term trends in supply and demand for natural gas. As of December 31, 2016, the remaining weighted average contract life of our natural gas transportation contracts (including intrastate pipelines' purchase and sales contracts) was approximately six years.

Our midstream assets provide gathering and processing services for natural gas and gathering services for crude oil. These assets are generally fee-based and the revenues and earnings we realize from gathering natural gas, processing natural gas in order to remove NGL from the natural gas stream, and fractionating NGL into their base components, are affected by the volumes of natural gas made available to our systems. Such volumes are impacted by producer rig count and drilling activity. In addition to fee based arrangements, we also provide some services based on percent-of-proceeds, percent-of-index and keep-whole contracts some of which may include minimum volume requirements. Our service contracts may rely solely on a single type of arrangement, but more often they combine elements of two or more of the above, which helps us and our counterparties manage the extent to which each shares in the potential risks and benefits of changing commodity prices.

The CO_2 source and transportation business primarily has third-party contracts with minimum volume requirements, which as of December 31, 2016, had a remaining average contract life of approximately nine years. CO_2 sales contracts vary from customer to customer and have evolved over time as supply and demand conditions have changed. Our recent contracts have generally provided for a delivered price tied to the price of crude oil, but with a floor price. On a volume-weighted basis, for third-party contracts making deliveries in 2017, and utilizing the average oil price per barrel contained in our 2017 budget, approximately 98% of our revenue is based on a fixed fee or floor price, and 2% fluctuates with the price of oil. In the long-term, our success in this portion of the CO_2 business segment is driven by the demand for CO_2. However, short-term changes in the demand for CO_2 typically do not have a significant impact on us due to the required minimum sales volumes under many of our contracts. In the CO_2 business segment's oil and gas producing activities, we monitor the amount of capital we expend in relation to the amount of production that we expect to add. In that regard, our production during any period is an important measure. In addition, the revenues we receive from our crude oil, NGL and CO_2 sales are affected by the prices we realize from the sale of these products. Over the long-term, we will tend to receive prices that are dictated by the demand and overall market price for these products. In the shorter term, however, market prices are likely not indicative of the revenues we will receive due to our risk management, or hedging, program, in which the prices to be realized for certain of our future sales quantities are fixed, capped or bracketed through the use of financial derivative contracts, particularly for crude oil. The realized weighted average crude oil price per barrel, with the hedges allocated to oil, was $61.52 per barrel in 2016, $73.11 per barrel in 2015, and $88.41 per barrel in 2014. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged

$41.36 per barrel in 2016, $47.56 per barrel in 2015, and $86.48 per barrel in 2014.

The factors impacting our Terminals business segment generally differ depending on whether the terminal is a liquids or bulk terminal, and in the case of a bulk terminal, the type of product being handled or stored. Our liquids terminals business generally has longer-term contracts that require the customer to pay regardless of whether they use the capacity. Thus, similar to our natural gas pipeline business, our liquids terminals business is less sensitive to short-term changes in supply and demand. Therefore, the extent to which changes in these variables affect our terminals business in the near term is a function of the length of the underlying service contracts (which on average is approximately four years), the extent to which revenues under the contracts are a function of the amount of product stored or transported, and the extent to which such contracts expire during any given period of time. As with our refined petroleum products pipeline transportation business, the revenues from our bulk terminals business are generally driven by the volumes we handle and/or store, as well as the prices we receive for our services, which in turn are driven by the demand for the products being shipped or stored. While we handle and store a large variety of products in our bulk terminals, the primary products are steel, coal and petroleum coke. For the most part, we have contracts for this business that contain minimum volume guarantees and/or service exclusivity arrangements under which customers are required to utilize our terminals for all or a specified percentage of their handling and storage needs. The profitability of our minimum volume contracts is generally unaffected by short-term variation in economic conditions; however, to the extent we expect volumes above the minimum and/or have contracts which are volume-based we can be sensitive to changing market conditions. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate the risk of reduced volumes and pricing by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. In addition, weather-related factors such as hurricanes, floods and droughts may impact our facilities and access to them and, thus, the profitability of certain terminals for limited periods of time or, in relatively rare cases of severe damage to facilities, for longer periods. In addition to liquid and bulk terminals, we also own Jones Act tankers. As of December 31, 2016, we have twelve Jones Act qualified tankers that operate in the marine transportation of crude oil, condensate and refined products in the U.S. and are currently operating pursuant to multi-year predominately fixed price charters with major integrated oil companies, major refiners and the U.S. Military Sealift Command.

The profitability of our refined petroleum products pipeline transportation and storage business is generally driven by the volume of refined petroleum products that we transport and the prices we receive for our services. We also have approximately 55 liquids terminals in this business segment that store fuels and offer blending services for ethanol and biofuels. The transportation and storage volume levels are primarily driven by the demand for the refined petroleum products being shipped or stored. Demand for refined petroleum products tends to track in large measure demographic and economic growth, and with the exception of periods of time with very high product prices or recessionary conditions, demand tends to be relatively stable. Because of that, we seek to own refined petroleum products pipelines located in, or that transport to, stable or growing markets and population centers. The prices for shipping are generally based on regulated tariffs that are adjusted annually based on changes in the U.S. Producer Price Index.

Our crude and condensate transportation services are primarily provided either pursuant to (i) long-term contracts that normally contain minimum volume commitments or (ii) through terms prescribed by the toll settlements with shippers and approved by regulatory authorities. As a result of these contracts, our settlement volumes are generally not sensitive to changing market conditions in the shorter term, however, in the longer term the revenues and earnings we realize from our crude and condensate pipelines in the U.S. and Canada are affected by the volumes of crude and condensate available to our pipeline systems, which are impacted by the level of oil and gas drilling activity in the respective producing regions that we serve. Our petroleum condensate processing facility splits condensate into its various components, such as light and heavy naphtha, under a long-term fee-based agreement with a major integrated oil company.

A portion of our business portfolio transacts in and/or uses the Canadian dollar as the functional currency, which affects segment results due to the variability in U.S. - Canadian dollar exchange rates. Our Canadian operations are included in three of our business segments: (i) our Kinder Morgan Canada segment, which is comprised of the Trans Mountain pipeline, an oversubscribed common carrier crude oil and refined petroleum pipeline serving western Canada, the Trans Mountain (Puget) pipeline serving Washington state; and the Jet Fuel pipeline serving Vancouver International Airport; (ii) terminal facilities located in western Canada that are included in our Terminals business segment; and (iii) the Canadian portion of our Cochin pipeline, which is included in our Products Pipelines business segment.

In our discussions of the operating results of individual businesses that follow (see "—Results of Operations" below), we generally identify the important fluctuations between periods that are attributable to acquisitions and dispositions separately from those that are attributable to businesses owned in both periods.

Critical Accounting Policies and Estimates

Accounting standards require information in financial statements about the risks and uncertainties inherent in significant estimates, and the application of GAAP involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates, and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others include our use of estimates in determining: (i) revenue recognition and income taxes, (ii) the economic useful lives of our assets and related depletion rates; (iii) the fair values used to assign purchase price from business combinations, determine possible asset and equity investment impairment charges, and calculate the annual goodwill impairment test; (iv) reserves for environmental claims, legal fees, transportation rate cases and other litigation liabilities; (v) provisions for uncollectible accounts receivables; and (vi) exposures under contractual indemnifications.

For a summary of our significant accounting policies, see Note 2 “Summary of Significant Accounting Policies” to our consolidated financial statements. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others, which policies are discussed as follows.

Acquisition Method of Accounting

For acquired businesses, we generally recognize the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their estimated fair values on the date of acquisition. Determining the fair value of these items requires management’s judgment, the utilization of independent valuation experts and involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired, the liabilities assumed and any noncontrolling interest in the investee, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. For more information on our acquisitions and application of the acquisition method, see Note 3 “Acquisitions and Divestitures” to our consolidated financial statements.

Environmental Matters

With respect to our environmental exposure, we utilize both internal staff and external experts to assist us in identifying environmental issues and in estimating the costs and timing of remediation efforts. We expense or capitalize, as appropriate, environmental expenditures that relate to current operations, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, we do not discount environmental liabilities to a net present value, and we recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable. We record at fair value, where appropriate, environmental liabilities assumed in a business combination.

Our recording of our environmental accruals often coincides with our completion of a feasibility study or our commitment to a formal plan of action, but generally, we recognize and/or adjust our environmental liabilities following routine reviews of potential environmental issues and claims that could impact our assets or operations. These adjustments may result in increases in environmental expenses and are primarily related to quarterly reviews of potential environmental issues and resulting environmental liability estimates. In making these liability estimations, we consider the effect of environmental compliance, pending legal actions against us, and potential third party liability claims. For more information on environmental matters, see Items 1 and 2 “Business and Properties—(c) Narrative Description of Business—Environmental Matters”. For more information on our environmental disclosures, see Note 17 “Litigation, Environmental and Other Contingencies” to our consolidated financial statements.

Legal and Regulatory Matters

Many of our operations are regulated by various U.S. and Canadian regulatory bodies and we are subject to legal and regulatory matters as a result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from orders, judgments or settlements. In general, we expense legal costs as incurred. When we identify contingent liabilities, we identify a range of possible costs expected to be required to resolve the matter. Generally, if no amount within this range is a better estimate than any other amount, we record a liability equal to the low end of the range. Any such liability recorded is revised as better information becomes available. Accordingly, to the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. For more information on legal proceedings, see Note 17 “Litigation, Environmental and Other Contingencies” to our consolidated financial statements.

Intangible Assets

Intangible assets are those assets which provide future economic benefit but have no physical substance. Identifiable intangible assets having indefinite useful economic lives, including goodwill, are not subject to regular periodic amortization, and such assets are not to be amortized until their lives are determined to be finite. Instead, the carrying amount of a recognized intangible asset with an indefinite useful life must be tested for impairment annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. We evaluate goodwill for impairment on May 31 of each year. At year end and during other interim periods we evaluate our reporting units for events and changes that could indicate that it is more likely than not that the fair value of a reporting unit could be less than its carrying amount.

Excluding goodwill, our other intangible assets include customer contracts, relationships and agreements, lease value, and technology-based assets. These intangible assets have definite lives, are being amortized in a systematic and rational manner over their estimated useful lives, and are reported separately as “Other intangibles, net” in our accompanying consolidated balance sheets.

Hedging Activities

We engage in a hedging program that utilizes derivative contracts to mitigate (offset) our exposure to fluctuations in energy commodity prices, foreign currency exposure on Euro denominated debt, and to balance our exposure to fixed and variable interest rates, and we believe that these hedges are generally effective in realizing these objectives. According to the provisions of GAAP, to be considered effective, changes in the value of a derivative contract or its resulting cash flows must substantially offset changes in the value or cash flows of the item being hedged, and any ineffective portion of the hedge gain or loss and any component excluded from the computation of the effectiveness of the derivative contract must be reported in earnings immediately.

All of our derivative contracts are recorded at estimated fair value. We utilize published prices, broker quotes, and estimates of market prices to estimate the fair value of these contracts; however, actual amounts could vary materially from estimated fair values as a result of changes in market prices. In addition, changes in the methods used to determine the fair value of these contracts could have a material effect on our results of operations. We do not anticipate future changes in the methods used to determine the fair value of these derivative contracts. For more information on our hedging activities, see Note 14, “Risk Management” to our consolidated financial statements.

Employee Benefit Plans

We reflect an asset or liability for our pension and other postretirement benefit plans based on their overfunded or underfunded status. As of December 31, 2016, our pension plans were underfunded by $724 million and our other postretirement benefits plans were underfunded by $141 million. Our pension and other postretirement benefit obligations and net benefit costs are primarily based on actuarial calculations. We use various assumptions in performing these calculations, including those related to the return that we expect to earn on our plan assets, the rate at which we expect the compensation of our employees to increase over the plan term, the estimated cost of health care when benefits are provided under our plan and other factors. A significant assumption we utilize is the discount rate used in calculating our benefit obligations. We utilize a full yield curve approach in the estimation of the service and interest cost components of net periodic benefit cost (credit) for our pension and other postretirement benefit plans which applies the specific spot rates along the yield curve used in the determination of the benefit obligation to their underlying projected cash flows. The selection of these assumptions is further discussed in Note 10 “Share-based Compensation and Employee Benefits” to our consolidated financial statements.
Actual results may differ from the assumptions included in these calculations, and as a result, our estimates associated with our pension and other postretirement benefits can be, and often are, revised in the future. The income statement impact of the changes in the assumptions on our related benefit obligations are deferred and amortized into income

over either the period of expected future service of active participants, or over the expected future lives of inactive plan participants. As of December 31, 2016, we had deferred net losses of approximately $613 million in pretax accumulated other comprehensive loss and noncontrolling interests related to our pension and other postretirement benefits.

The following table shows the impact of a 1% change in the primary assumptions used in our actuarial calculations associated with our pension and other postretirement benefits for the year ended December 31, 2016:

	Pension Benefits		Other Postretirement Benefits	
	Net benefit cost (income)	Change in funded status(a)	Net benefit cost (income)	Change in funded status(a)
	(In millions)			
One percent increase in:				
Discount rates	$(10)	$ 236	$ (1)	$ 37
Expected return on plan assets	(21)	—	(3)	—
Rate of compensation increase	4	(11)	—	—
Health care cost trends	—	—	3	(31)
One percent decrease in:				
Discount rates	12	(278)	—	(42)
Expected return on plan assets	21	—	3	—
Rate of compensation increase	(3)	10	—	—
Health care cost trends	—	—	(4)	27

(a) Includes amounts deferred as either accumulated other comprehensive income (loss) or as a regulatory asset or liability for certain of our regulated operations.

Income Taxes

Income tax expense is recorded based on an estimate of the effective tax rate in effect or to be in effect during the relevant periods. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. We do business in a number of states with differing laws concerning how income subject to each state's tax structure is measured and at what effective rate such income is taxed. Therefore, we must make estimates of how our income will be apportioned among the various states in order to arrive at an overall effective tax rate. Changes in our effective rate, including any effect on previously recorded deferred taxes, are recorded in the period in which the need for such change is identified.

Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Deferred tax assets are reduced by a valuation allowance for the amount that is more likely than not to be realized. While we have considered estimated future taxable income and prudent and feasible tax planning strategies in determining the amount of our valuation allowance, any change in the amount that we expect to ultimately realize will be included in income in the period in which such a determination is reached.

In determining the deferred income tax asset and liability balances attributable to our investments, we apply an accounting policy that looks through our investments. The application of this policy resulted in no deferred income taxes being provided on the difference between the book and tax basis on the non-tax-deductible goodwill portion of our investments.

Results of Operations

Overview

Our management evaluates our performance primarily using the measures of Segment EBDA and, as discussed below under "—Non-GAAP Measures," distributable cash flow, or DCF, and Segment EBDA before certain items. Segment EBDA is a useful measure of our operating performance because it measures the operating results of our segments before DD&A and certain expenses that are generally not controllable by our business segment operating managers, such as general and administrative expenses, interest expense, net, and income taxes. Our general and administrative expenses include such items as employee benefits, insurance, rentals, unallocated litigation and environmental expenses, and shared corporate services including accounting, information technology, human resources and legal services.

Segment results for the years ended December 31, 2015 and 2014 have been retrospectively adjusted to reflect the elimination of the Other segment as a reportable segment. The activities that previously comprised the Other segment are now presented within the Corporate non-segment activities in reconciling to the consolidated totals in the respective segment reporting tables. The Other segment had historically been comprised primarily of legacy operations of acquired businesses not associated with our ongoing operations. These business activities have since been sold or have otherwise ceased. In addition, the Other segment included certain company owned real estate assets which are primarily leased to our operating subsidiaries as well as third party tenants. This activity is now reflected within Corporate activity. In addition, the portions of interest income and income tax expense previously allocated to our business segments are now included in "Interest expense, net" and "Income tax expense" for all periods presented in the following tables.

Consolidated Earnings Results

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Segment EBDA(a)			
Natural Gas Pipelines	$3,211	$3,067	$4,264
CO_2	827	658	1,248
Terminals	1,078	878	973
Products Pipelines	1,067	1,106	856
Kinder Morgan Canada	181	182	200
Total segment EBDA(b)	6,364	5,891	7,541
DD&A	(2,209)	(2,309)	(2,040)
Amortization of excess cost of equity investments	(59)	(51)	(45)
General and administrative expenses(c)	(669)	(690)	(610)
Interest expense, net(d)	(1,806)	(2,051)	(1,798)
Corporate(e)	17	(18)	43
Income before income taxes	1,638	772	3,091
Income tax expense	(917)	(564)	(648)
Net income	721	208	2,443
Net (income) loss attributable to noncontrolling interests	(13)	45	(1,417)
Net income attributable to Kinder Morgan, Inc.	708	253	1,026
Preferred Stock Dividends	(156)	(26)	—
Net Income Available to Common Stockholders	$552	$227	$1,026

(a) Includes revenues, earnings from equity investments, and other, net, less operating expenses, other expense (income), net, losses on impairments of goodwill, losses on impairments and divestitures, net and losses on impairments and divestitures of equity investments, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes.

Certain items affecting Total Segment EBDA (see "—Non-GAAP Measures" below)

(b) 2016, 2015 and 2014 amounts include decreases in earnings of $1,121 million, $1,748 million and $67 million, respectively, related to the combined net effect of the certain items impacting Total Segment EBDA. The extent to which these items affect each of our business segments is discussed below in the footnotes to the tables within "—Segment Earnings Results."

(c) 2016, 2015 and 2014 amounts include decreases (increase) to expense of $5 million, $(25) million and $28 million, respectively, related to the combined net effect of the certain items related to general and administrative expenses disclosed below in "—General and Administrative, Interest, Corporate and Noncontrolling Interests."

(d) 2016, 2015 and 2014 amounts include decreases in expense of $193 million, $27 million and $3 million, respectively, related to the combined net effect of the certain items related to interest expense, net disclosed below in "—General and Administrative, Interest, Corporate and Noncontrolling Interests."

(e) 2016, 2015 and 2014 amounts include decreases (increase) to expense of $8 million, $(35) million and $22 million, respectively, related to the combined net effect of the certain items related to Corporate activities disclosed below in "—General and Administrative, Interest, Corporate and Noncontrolling Interests.

Year Ended December 31, 2016 vs. 2015

The certain item totals reflected in footnotes (b), (c), (d) and (e) to the table above accounted for $866 million of the increase in income before income taxes in 2016 as compared to 2015 (representing the difference between decreases of $915 million and $1,781 million in income before income taxes for 2016 and 2015, respectively). After giving effect to these certain items, which are discussed in more detail in the discussion that follows, income before income taxes for 2016 when compared to the prior year was flat. Increased results in our Products Pipelines and Terminals business segments and decreased DD&A expense and interest expense, net, were offset by unfavorable commodity prices affecting our CO_2 business segment and decreased results on our Natural Gas Pipelines business segment. The decrease in DD&A was primarily driven by lower DD&A in our CO_2 business segment and the decrease in interest expense was due to lower weighted average debt balances, partially offset by a slightly higher overall weighted average interest rate on outstanding debt.

Year Ended December 31, 2015 vs. 2014

The certain item totals reflected in footnotes (b), (c), (d) and (e) to the table above accounted for $1,767 million of the decrease in income before income taxes in 2015 as compared to 2014 (representing the difference between decreases of $1,781 million and $14 million in income before income taxes for 2015 and 2014, respectively). After giving effect to these certain items, which are discussed in more detail in the discussion that follows, the remaining decrease of $552 million (18%) from the prior year in income before income taxes is primarily attributable to increased DD&A expense, general and administrative expense and interest expense, net. As explained further below, our total segment earnings before DD&A did not change significantly when compared to the prior year as unfavorable commodity prices affecting our CO_2 business segment were offset by increased results from our Products Pipelines, Terminals and Natural Gas Pipelines business segments.

Non-GAAP Financial Measures

Our non-GAAP performance measures are DCF, both in the aggregate and per share, and Segment EBDA before certain items. Certain items are items that are required by GAAP to be reflected in net income, but typically either (i) do not have a cash impact (for example, asset impairments), or (ii) by their nature are separately identifiable from our normal business operations and in our view are likely to occur only sporadically (for example certain legal settlements, hurricane impacts and casualty losses).

Our non-GAAP performance measures described below should not be considered alternatives to GAAP net income or other GAAP measures and have important limitations as analytical tools. Our computations of DCF and Segment EBDA before certain items may differ from similarly titled measures used by others. You should not consider these non-GAAP performance measures in isolation or as substitutes for an analysis of our results as reported under GAAP. DCF should not be used as an alternative to net cash provided by operating activities computed under GAAP. Management compensates for the limitations of these non-GAAP performance 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.

Distributable Cash Flow

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 performance measure and believes it provides users of our financial statements a useful performance 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. A reconciliation of DCF to net income available to common stockholders is provided in the table below. DCF per share is DCF divided by average outstanding shares, including restricted stock awards that participate in dividends.

Segment EBDA Before Certain Items

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 performance 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).

In the tables for each of our business segments under "— Segment Earnings Results" below, Segment EBDA before certain items is calculated by adjusting the Segment EBDA for the applicable certain item amounts, which are totaled in the tables and described in the footnotes to those tables.

Reconciliation of Net Income Available to Common Stockholders to DCF

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Net Income Available to Common Stockholders	$552	$227	$1,026
Add/(Subtract):			
Certain items before book tax(a)	915	1,781	14
Book tax certain items(b)	18	(340)	(117)
Certain items after book tax	933	1,441	(103)
Noncontrolling interest certain items(c)	(8)	(63)	—
Net income available to common stockholders before certain items	1,477	1,605	923
Add/(Subtract):			
DD&A expense(d)	2,617	2,683	2,390
Total book taxes(e)	993	976	840
Cash taxes(f)	(79)	(32)	(448)
Other items(g)	43	32	17
Sustaining capital expenditures(h)	(540)	(565)	(509)
Net income attributable to noncontrolling interests of our former master limited partnerships	—	—	1,405
Declared distributions to noncontrolling interests(i)	—	—	(2,000)
DCF	$4,511	$4,699	$2,618
Weighted average common shares outstanding for dividends(j)	2,238	2,200	1,312
DCF per common share	$2.02	$2.14	$2.00
Declared dividend per common share	0.500	1.605	1.740

(a) Consists of certain items summarized in footnotes (b) through (e) to the "—Results of Operations—Consolidated Earnings Results" table included above, and described in more detail below in the footnotes to tables included in both our management's discussion and analysis of segment results and "—General and Administrative, Interest, Corporate and Noncontrolling Interests."

(b) Represents income tax provision on certain items plus discrete income tax items. For 2016, discrete income tax items included a $276 million increase in tax expense primarily due to the impact of the sale of a 50% interest in SNG discussed in Note 5 "Income Taxes" to our consolidated financial statements.

(c) Represents noncontrolling interests share of certain items.

(d) Includes DD&A, amortization of excess cost of equity investments and our share of equity investee's DD&A of $349 million, $323 million and $305 million in 2016, 2015 and 2014, respectively.

(e) Excludes book tax certain items. 2016, 2015 and 2014 amounts also include $94 million, $72 million and $75 million, respectively, of our share of taxable equity investee's book tax expense.

(f) Includes our share of taxable equity investee's cash taxes of $(76) million, $(19) million and $(27) million in 2016, 2015 and 2014, respectively.

(g) For 2016 and 2015, consists primarily of non-cash compensation associated with our restricted stock awards program and for 2014 consists primarily of excess coverage from our former master limited partnerships.

(h) Includes our share of equity investee's sustaining capital expenditures of $(90) million, $(70) million and $(59) million in 2016, 2015 and 2014, respectively.

(i) Represents distributions to KMP and EPB limited partner units formerly owned by the public for the respective period.

(j) Includes restricted stock awards that participate in common share dividends and, for 2015, the dilutive effect of warrants. 2014 amount also includes the common shares issued on November 26, 2014 for the Merger Transactions as if outstanding for the entire fourth quarter which differs from our GAAP presentation on our Consolidated Statement of Income.

Segment Earnings Results

Natural Gas Pipelines

	Year Ended December 31,		
	2016	2015	2014
	(In millions, except operating statistics)		
Revenues(a)	$8,005	$8,725	$10,168
Operating expenses	(4,393)	(4,738)	(6,241)
Loss on impairment of goodwill(b)	—	(1,150)	—
Loss on impairments and divestitures, net(b)	(200)	(122)	(5)
Other income	1	3	—
Earnings from equity investments	385	351	318
Loss on impairments of equity investments(b)	(606)	(26)	—
Other, net	19	24	24
Segment EBDA(b)(c)	3,211	3,067	4,264
Certain items(b)	825	1,062	(190)
Segment EBDA before certain items(c)	$4,036	$4,129	$4,074

Change from prior period	Increase/(Decrease)	
Revenues before certain items	$(477)	$(1,479)
Segment EBDA before certain items	$(93)	$55

Natural gas transport volumes (BBtu/d)(d)	28,095	28,196	26,917
Natural gas sales volumes (BBtu/d)	2,335	2,419	2,334
Natural gas gathering volumes (BBtu/d)(d)	2,970	3,540	3,394
Crude/condensate gathering volumes (MBbl/d)(d)	308	340	298

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Certain items affecting Segment EBDA

(a) 2016 and 2014 amounts include decreases in revenues of $50 million and $2 million, respectively, and 2015 amount includes an increase in revenues of $32 million, all related to non-cash mark-to-market derivative contracts used to hedge forecasted natural gas, NGL and crude oil sales. 2016 amount also includes an increase in revenue of $39 million associated with revenue collected on a customer’s early buyout of a long-term natural gas storage contract. 2015 and 2014 amounts also include increases in revenues of $200 million and $198 million, respectively, associated with amounts collected on the early termination of long-term natural gas transportation contracts on KMLP.

(b) In addition to the revenue certain items described in footnote (a) above, 2016 amount also includes (i) $613 million related to equity investment impairments primarily related to our investments in MEP and Ruby; (ii) a decrease in earnings of $106 million of project write-offs; (iii) an $84 million pre-tax loss on the sale of a 50% interest in our SNG natural gas pipeline system; (iv) an increase in earnings of $18 million related to the early termination of a customer contract at an equity investee; and (v) a decrease in earnings of $29 million from other certain items. 2015 amount also includes (i) $1,150 million of losses related to goodwill impairments on our non-regulated midstream reporting unit; (ii) $52 million of losses related to divestitures of our non-regulated midstream assets; (iii) $47 million of losses related to other impairments on our non-regulated midstream assets; (iv) $26 million of impairments on equity investments; and (v) a $19 million net decrease in earnings related to project write-offs and other certain items. 2014 amount also includes a $6 million decrease in earnings from other certain items.

Other

(c) Income tax expense and interest income that were allocated to and presented in Segment EBDA in prior periods are presented herein in income tax expense and interest expense, net, respectively, to conform to our current presentation as discussed above in “—Overview.” The amounts for 2016, 2015 and 2014 were $7 million, $4 million and $6 million, respectively, in income tax expense and for 2014, $1 million in interest income.

(d) Joint venture throughput is reported at our ownership share. Volumes for acquired pipelines are included at our ownership share for the entire period, however, EBDA contributions from acquisitions are included only for the periods subsequent to their acquisition.

Below are the changes in both Segment EBDA before certain items and revenues before certain items in 2016 and 2015, when compared with the respective prior year:

Year Ended December 31, 2016 versus Year Ended December 31, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
SNG	$(109)	(25)%	$ (188)	(33)%
South Texas Midstream	(62)	(18)%	(229)	(18)%
KinderHawk	(48)	(36)%	(51)	(33)%
KMLP	(31)	(135)%	(34)	(100)%
CIG	(27)	(9)%	(31)	(8)%
CPG	(22)	(37)%	(23)	(29)%
TransColorado	(15)	(48)%	(16)	(42)%
TGP	171	18%	205	17%
Hiland Midstream	59	42%	152	38%
Texas Intrastate Natural Gas Pipeline Operations	7	2%	(278)	(9)%
All others (including eliminations)	(16)	(1)%	16	1%
Total Natural Gas Pipelines	$(93)	(2)%	$ (477)	(6)%

The changes in Segment EBDA for our Natural Gas Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2016 and 2015:

- decrease of $109 million (25%) from SNG primarily due to our sale of a 50% interest in SNG to The Southern Company (Southern Company) on September 1, 2016;
- decrease of $62 million (18%) from South Texas Midstream primarily due to lower volumes and price. Revenue decreased approximately $229 million partially offset by a decrease in costs of sales;
- decrease of $48 million (36%) from KinderHawk due to lower volumes;
- decrease of $31 million (135%) from KMLP as a result of a customer contract buyout in the fourth quarter of 2015;
- decrease of $27 million (9%) from CIG primarily due to a recent rate case settlement and lower firm reservation revenues due to contract expirations and contract renewals at lower rates;
- decrease of $22 million (37%) from CPG primarily due to lower transport revenues as a result of contract expirations;
- decrease of $15 million (48%) from TransColorado primarily due to lower transport revenues as a result of contract expirations;
- increase of $171 million (18%) from TGP primarily due to a full year of earnings from expansion projects placed in service during 2015 and favorable 2016 firm transport revenues;
- increase of $59 million (42%) from Hiland Midstream primarily due to favorable margins on renegotiated contracts, along with results of a full year from our February 2015 Hiland acquisition; and
- increase of $7 million (2%) from our Texas intrastate natural gas pipeline operations (including the operations of its Kinder Morgan Tejas, Border, Kinder Morgan Texas, North Texas and Mier-Monterrey Mexico pipeline systems) primarily due to higher storage margins partially offset by lower sales and transportation margins as a result of lower volumes. The decrease in revenues of $278 million resulted primarily from a decrease in sales revenue due to lower commodity prices which was largely offset by a corresponding decrease in costs of sales.

Year Ended December 31, 2015 versus Year Ended December 31, 2014

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Hiland Midstream	$140	n/a	$404	n/a
TGP	36	4%	48	4%
EPNG	35	9%	56	10%
EagleHawk(a)	31	443%	n/a	n/a
Texas Intrastate Natural Gas Pipeline Operations	15	4%	(1,231)	(30)%
KinderHawk	(67)	(34)%	(69)	(31)%
Oklahoma Midstream	(38)	(57)%	(247)	(47)%
KMLP	(33)	(59)%	(34)	(50)%
CPG	(24)	(29)%	(24)	(24)%
Altamont Midstream	(21)	(35)%	(60)	(37)%
South Texas Midstream	(9)	(3)%	(417)	(25)%
All others (including eliminations)	(10)	(1)%	95	7%
Total Natural Gas Pipelines	$55	1%	$(1,479)	(15)%

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n/a - not applicable
(a) Equity investment.

The changes in Segment EBDA for our Natural Gas Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2015 and 2014:

- increase of $140 million from our February 2015 acquisition of the Hiland Midstream asset;
- increase of $36 million (4%) from TGP primarily due to higher revenues from firm transportation and storage services due largely to expansion projects placed in service in the fourth quarter 2014 and during 2015. Partially offsetting this was an increase in the provision for revenue sharing during 2015, lower transportation usage revenues and natural gas park and loan revenues due to milder winter weather in 2015 and higher ad valorem taxes;
- increase of $35 million (9%) from EPNG due largely to additional firm transport revenues due, in part, to additional demand from Mexico;
- increase of $31 million (443%) from EagleHawk driven by higher volumes and lower pipeline integrity costs;
- increase of $15 million (4%) from our Texas Intrastate Natural Gas Pipeline operations (including the operations of its Kinder Morgan Tejas, Border, Kinder Morgan Texas, North Texas and Mier-Monterrey Mexico pipeline systems) due largely to higher transportation and natural gas sales margins as a result of new customer contracts, partially offset by lower processing margins due to the non-renewal of a customer contract in the second quarter of 2014 and lower storage margins. The decrease in revenues of $1,231 million and associated decrease in costs of goods sold were caused by lower natural gas prices;
- decrease of $67 million (34%) from KinderHawk primarily due to the expiration of a minimum volume contract;
- decrease of $38 million (57%) from Oklahoma Midstream primarily due to lower commodity prices and lower volumes. Lower revenues of $247 million and associated decrease in costs of goods sold were also due to lower commodity prices;
- decrease of $33 million (59%) from KMLP as a result of a customer contract buyout in the third quarter of 2014;
- decrease of $24 million (29%) from CPG due primarily to lower transport revenues as a result of contract expirations;
- decrease of $21 million (35%) from Altamont Midstream primarily due to lower commodity prices partially offset by higher volumes; and
- decrease of $9 million (3%) from South Texas Midstream primarily due to lower commodity prices, partially offset by higher gathering and processing volumes. Lower revenues of $417 million and associated decrease in costs of goods

sold were due to lower commodity prices.

CO2

	Year Ended December 31,		
	2016	2015	2014
	(In millions, except operating statistics)		
Revenues(a)	$ 1,221	$ 1,699	$ 1,960
Operating expenses	(399)	(432)	(494)
Loss on impairments and divestitures, net(b)	(19)	(606)	(243)
Earnings from equity investments(b)	24	(3)	25
Segment EBDA(b)(c)	827	658	1,248
Certain items(b)	92	484	218
Segment EBDA before certain items(c)	$ 919	$ 1,142	$ 1,466
Change from prior period	Increase/(Decrease)		
Revenues before certain items	$ (267)	$ (384)	
Segment EBDA before certain items	$ (223)	$ (324)	
Southwest Colorado CO_2 production (gross) (Bcf/d)(d)	1.2	1.2	1.3
Southwest Colorado CO_2 production (net) (Bcf/d)(d)	0.6	0.6	0.5
SACROC oil production (gross)(MBbl/d)(e)	29.3	33.8	33.2
SACROC oil production (net)(MBbl/d)(f)	24.4	28.1	27.6
Yates oil production (gross)(MBbl/d)(e)	18.4	19.0	19.5
Yates oil production (net)(MBbl/d)(f)	8.2	8.5	8.8
Katz, Goldsmith, and Tall Cotton Oil Production - Gross (MBbl/d)(e)	7.0	5.7	4.9
Katz, Goldsmith, and Tall Cotton Oil Production - Net (MBbl/d)(f)	5.9	4.8	4.1
NGL sales volumes (net)(MBbl/d)(f)	10.3	10.4	10.1
Realized weighted-average oil price per Bbl(g)	$ 61.52	$ 73.11	$ 88.41
Realized weighted-average NGL price per Bbl(h)	$ 17.91	$ 18.35	$ 41.87

Certain items affecting Segment EBDA

(a) 2016, 2015 and 2014 amounts include an unrealized loss of $63 million, and unrealized gains of $138 million and $25 million, respectively, all relating to derivative contracts used to hedge forecasted commodity sales. 2015 amount also includes a favorable adjustment of $10 million related to carried working interest at McElmo Dome.

(b) In addition to the revenue certain items described in footnote (a) above: 2016 amount also includes a decrease of $9 million in equity earnings for our share of a project write-off recorded by an equity investee and a $20 million increase in expense related to source and transportation project write-offs. 2015 amount also includes (i) oil and gas property impairments of $399 million; (ii) project write-offs of $207 million; and (iii) a $26 million decrease in equity earnings for our share of a project write-off. 2014 amount also includes oil and gas property impairments of $243 million.

Other

(c) Income tax expense that was allocated to and presented in Segment EBDA in prior periods is presented herein in income tax expense to conform to our current presentation as discussed above in "—Overview." The amounts for 2016, 2015 and 2014 were $2 million, $1 million and $8 million, respectively, in income tax expense.

(d) Includes McElmo Dome and Doe Canyon sales volumes.

(e) Represents 100% of the production from the field. We own approximately 97% working interest in the SACROC unit, an approximately 50% working interest in the Yates unit, an approximately 99% working interest in the Katz unit and a 99% working interest in the Goldsmith Landreth unit and a 100% working interest in the Tall Cotton field.

(f) Net after royalties and outside working interests.

(g) Includes all crude oil production properties.

(h) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

Below are the changes in both Segment EBDA before certain items and revenues before certain items in 2016 and 2015, when compared with the respective prior year:
Year Ended December 31, 2016 versus Year Ended December 31, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Source and Transportation Activities	$(27)	(8)%	$ (36)	(9)%
Oil and Gas Producing Activities	(196)	(24)%	(241)	(20)%
Intrasegment eliminations	—	—%	10	21%
Total CO2	$(223)	(20)%	$ (267)	(17)%

The changes in Segment EBDA for our CO_2 business segment are further explained by the significant factors driving Segment EBDA before certain items in the comparable years of 2016 and 2015 which factors include lower revenues of $205 million from lower commodity prices and $72 million due to decreased volumes, partially offset by (i) $27 million in reduced operating costs; (ii) $15 million of lower severance and ad valorem tax expenses; and (iii) $11 million primarily related to increased earnings from an equity investee.

Year Ended December 31, 2015 versus Year Ended December 31, 2014

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Source and Transportation Activities	$(122)	(27)%	$ (116)	(23)%
Oil and Gas Producing Activities	(202)	(20)%	(303)	(20)%
Intrasegment Eliminations	—	—%	35	42%
Total CO2	$(324)	(22)%	$ (384)	(20)%

The changes in Segment EBDA for our CO_2 business segment are further explained by the significant factors driving Segment EBDA before certain items in the comparable years of 2015 and 2014 which factors include lower revenues of $405 million from lower commodity prices partially offset by $62 million of increased volumes and $27 million in reduced operating expenses.

Terminals

	Year Ended December 31,		
	2016	2015	2014
	(In millions, except operating statistics)		
Revenues(a)	$ 1,922	$ 1,879	$ 1,718
Operating expenses	(768)	(836)	(746)
Loss on impairments and divestitures, net(b)	(99)	(191)	(29)
Other income	—	1	—
Earnings from equity investments	35	21	18
Loss on impairments and divestitures of equity investments, net(b)	(16)	(4)	—
Other, net	4	8	12
Segment EBDA(b)(c)	1,078	878	973
Certain items, net(b)	91	206	35
Segment EBDA before certain items(c)	$ 1,169	$ 1,084	$ 1,008
Change from prior period	Increase/(Decrease)		
Revenues before certain items	$ 38	$ 156	
Segment EBDA before certain items	$ 85	$ 76	
Bulk transload tonnage (MMtons)(d)	61.8	63.2	79.8
Ethanol (MMBbl)	66.7	63.1	66.5
Liquids leaseable capacity (MMBbl)	87.8	81.5	77.8
Liquids utilization %(e)	94.8 %	93.6 %	95.3 %

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Certain items affecting Segment EBDA

(a) 2016, 2015 and 2014 amounts include increases in revenues of $28 million, $23 million and $18 million, respectively, from the amortization of a fair value adjustment (associated with the below market contracts assumed upon acquisition) from our Jones Act tankers.

(b) In addition to the revenue certain items described in footnote (a) above: 2016 amount also includes increases in expense of $103 million related to losses on impairments and divestitures, net and $16 million related to losses on impairments and divestitures of equity investments, net. 2015 amount also includes (i) a $175 million non-cash pre-tax impairment of a terminal facility reflecting the impact of an agreement to adjust certain payment terms under a contract with a coal customer; (ii) a $34 million increase in bad debt expense due to certain coal customers bankruptcies related to revenues recognized in prior years but not yet collected; and (iii) $20 million primarily related to other impairment charges. 2014 amount also includes a $29 million write-down associated with a sale of certain terminals to a third-party and $24 million of increased expense from other certain items.

Other

(c) Income tax expense that was allocated to and presented in Segment EBDA in prior periods is presented herein in income tax expense to conform to our current presentation as discussed above in “—Overview.” The amounts for 2016, 2015 and 2014 were $42 million, $29 million and $29 million, respectively, in income tax expense.

(d) Includes our proportionate share of joint venture tonnage.

(e) The ratio of our actual leased capacity to our estimated capacity.

Below are the changes in both Segment EBDA before certain items and revenues before certain items in 2016 and 2015, when compared with the respective prior year:
Year Ended December 31, 2016 versus Year Ended December 31, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Marine Operations	$52	51%	$ 73	46%
Alberta, Canada	14	12%	19	14%
Gulf Liquids	14	6%	18	5%
Northeast	11	10%	19	10%
Lower River	4	7%	(12)	(9)%
Gulf Bulk	(13)	(17)%	(50)	(29)%
Held for sale operations	(2)	(67)%	(18)	(100)%
All others (including intrasegment eliminations)	5	1%	(11)	(2)%
Total Terminals	$85	8%	$ 38	2%

The changes in Segment EBDA for our Terminals business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2016 and 2015:

- increase of $52 million (51%) from our Marine Operations related to the incremental earnings from the December 2015, May 2016, July 2016, September 2016 and December 2016 in-service of the Jones Act tankers the Lone Star State, Magnolia State, Garden State, Bay State,and American Endurance, respectively, and increased charter rates on the Empire State Jones Act tanker;
- increase of $14 million (12%) from our Alberta, Canada terminals, driven by a full year of earnings from our Edmonton South rail terminal joint venture expansion, which began operations in second quarter 2015;
- increase of $14 million (6%) from our Gulf Liquids terminals, primarily related to higher volumes as a result of various expansion projects, including marine infrastructure improvements at our Galena Park and North Docks terminals, as well as higher rates and ancillary service activities on existing business;
- increase of $11 million (10%) from our Northeast terminals, primarily due to contributions from two terminals acquired as part of the BP Products North America Inc. acquisition which was completed in February 2016;
- increase of $4 million (7%) from our Lower River terminals, due to a $15 million write-off of certain coal customers accounts receivable which occurred in 2015 and favorable results from certain Lower River terminals, partially offset by decreased revenues and earnings of $18 million due to certain coal customer bankruptcies;
- decrease of $13 million (17%) from our Gulf Bulk terminals, driven by decreased revenues and earnings of $41 million due to certain coal customer bankruptcies offset by a $28 million write-off of a certain coal customer’s accounts receivable which occurred in the fourth quarter of 2015;
- decrease of $2 million (67%) from our sale of certain bulk and transload terminal facilities to Watco Companies, LLC in early 2015; and
- included in “All others” is a decrease in revenues and earnings of $11 million due to certain coal customer bankruptcies as compared to a $4 million write-off of certain coal customers accounts receivable which occurred in 2015.

Year Ended December 31, 2015 versus Year Ended December 31, 2014

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Alberta, Canada	$52	76%	$ 67	102%
Marine Operations	44	n/a	57	n/a
Gulf Liquids	24	11%	41	14%
Gulf Central	23	52%	30	51%
Held for sale operations	(17)	(77)%	(57)	(67)%
Gulf Bulk	(16)	(18)%	22	15%
Mid Atlantic	(21)	(29)%	(25)	(18)%
All others (including intrasegment eliminations)	(13)	(3)%	21	3%
Total Terminals	$76	8%	$ 156	9%

n/a – not applicable

The changes in Segment EBDA for our Terminals business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2015 and 2014:

- increase of $52 million (76%) from our Alberta, Canada terminals, driven by our Edmonton-area expansion projects, including storage and connectivity additions at our Edmonton South and North 40 terminals as well as the commissioning of two joint venture rail terminals;
- increase of $44 million from our Marine Operations related primarily to the incremental earnings from the Jones Act tankers we acquired in the first and fourth quarters of 2014 as well as the December 2015 delivery from the NASSCO shipyard of the first new build tanker, the Lone Star State;
- increase of $24 million (11%) from our Gulf Liquids terminals, related to the Vopak terminal acquisition completed in first quarter 2015 and the addition of nine new tanks at Galena Park placed into service during fourth quarter 2014 and first quarter 2015;
- increase of $23 million (52%) from our Gulf Central terminals, driven by higher earnings from our expansion projects at our joint venture terminals, Battleground Oil Specialty Terminal Company LLC (BOSTCO) and Deeprock Development LLC;
- decrease of $17 million (77%) from our sale of certain bulk and transload terminal facilities to Watco Companies, LLC in early 2015;
- decrease of $16 million (18%) from our Gulf Bulk terminals, primarily from reduced coal earnings due to certain coal customers bankruptcies of $27 million partially offset by increased shortfall revenue from take-or-pay coal contracts;
- decrease of $21 million (29%) from our Mid Atlantic terminals, driven by lower revenues as a result of lower tonnage partially offset by higher shortfall revenue from take-or-pay coal contracts; and
- decrease of $21 million primarily from reduced coal earnings due to certain coal customers bankruptcies, which impacted our International Marine Terminals and Mid River terminals included in “All others” and the Mid Atlantic terminals noted above by $16 million, $3 million and $2 million, respectively.

Products Pipelines

	Year Ended December 31,		
	2016	2015	2014
	(In millions, except operating statistics)		
Revenues	$ 1,649	$ 1,831	$ 2,068
Operating expenses	(573)	(772)	(1,258)
Loss on impairments and divestitures, net(a)	(76)	—	—
Other (expense) income	—	(2)	3
Earnings from equity investments	53	45	44
Gain on divestiture of equity investment(a)	12	—	—
Other, net	2	4	(1)
Segment EBDA(a)(b)	1,067	1,106	856
Certain items(a)	113	(4)	4
Segment EBDA before certain items(b)	$ 1,180	$ 1,102	$ 860
Change from prior period	Increase/(Decrease)		
Revenues	$ (182)	$ (237)	
Segment EBDA before certain items	$ 78	$ 242	
Gasoline (MMBbl) (c)	374.3	368.9	359.2
Diesel fuel (MMBbl)	124.9	129.1	126.9
Jet fuel (MMBbl)	105.2	103.1	100.5
Total refined product volumes (MMBbl)(d)	604.4	601.1	586.6
NGL (MMBbl)(d)	39.7	38.6	25.3
Condensate (MMBbl)(d)	118.3	99.7	33.2
Total delivery volumes (MMBbl)	762.4	739.4	645.1
Ethanol (MMBbl)(e)	41.3	41.4	41.6

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Certain items affecting Segment EBDA

(a) 2016 amount includes increases in expense of (i) $65 million related to the Palmetto project write-off; (ii) $31 million of rate case liability estimate adjustments associated with prior periods; (iii) $20 million related to a legal settlement; and (iv) $9 million of non-cash impairment charges related to the sale of a Transmix facility; offset by a $12 million gain related to the sale of an equity investment. 2015 and 2014 amounts include a $4 million decrease in expense and a $4 million increase in expense, respectively, associated with a certain Pacific operations litigation matter.

Other

(b) Income tax expense and interest income that were allocated to and presented in Segment EBDA in prior periods are presented herein in income tax expense and interest expense, net, respectively, to conform to our current presentation as discussed above in "—Overview."

The amounts for 2016, 2015 and 2014 were $(5) million, $8 million and $2 million, respectively, in income tax (benefit) expense and for 2015 and 2014, $2 million and $(2) million, respectively in interest income (expense).

(c) Volumes include ethanol pipeline volumes.

(d) Joint Venture throughput is reported at our ownership share.

(e) Represents total ethanol volumes, including ethanol pipeline volumes included in gasoline volumes above.

Below are the changes in both Segment EBDA before certain items and revenues before certain items in 2016 and 2015, when compared with the respective prior year:

Year Ended December 31, 2016 versus Year Ended December 31, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Crude & Condensate Pipeline	$37	20%	$ 36	18%
KMCC - Splitter	20	53%	30	71%
Double H pipeline	15	34%	22	39%
Plantation Pipe Line	9	17%	1	5%
Transmix	8	26%	(286)	(57)%
Cochin	(13)	(11)%	3	2%
All others (including eliminations)	2	—%	12	1%
Total Products Pipelines	$78	7%	$ (182)	(10)%

The changes in Segment EBDA for our Products Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2016 and 2015:

- increase of $37 million (20%) from Kinder Morgan Crude & Condensate Pipeline driven primarily by an increase in pipeline throughput volumes from existing customers and additional volumes associated with expansion projects;
- increase of $20 million (53%) from our KMCC - Splitter due to first and second phases being in full operation for 2016. Start up of first phase was in March 2015 and second phase was in July 2015;
- increase of $15 million (34%) due to full year of results from our Double H pipeline, which began operations in March 2015;
- increase of $9 million (17%) from our equity investment in Plantation Pipe Line primarily due to lower operating costs;
- increase of $8 million (26%) from our Transmix processing operations largely due to unfavorable market price impacts during the fourth quarter of 2015. The decrease in revenues of $286 million and associated decrease in costs of goods sold were driven by lower sales volumes primarily due to the sale of our Indianola plant in August 2016; and
- decrease of $13 million (11%) from Cochin primarily due to higher pipeline integrity costs.

Year Ended December 31, 2015 versus Year Ended December 31, 2014

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Crude & Condensate Pipeline	$102	124%	$ 90	81%
KMCC - Splitter	33	n/a	43	n/a
Double H pipeline	44	n/a	56	n/a
Cochin	35	40%	54	50%

Pacific operations	23	7%	27	6%
Transmix operations	8	33%	(490)	(49)%
All others (including eliminations)	(3)	(1)%	(17)	(4)%
Total Products Pipelines	$242	28%	$ (237)	(12)%

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n/a - not applicable

The changes in Segment EBDA for our Products Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2015 and 2014:

- increase of $102 million (124%) from Kinder Morgan Crude & Condensate Pipeline driven primarily by an increase of pipeline throughput volumes due to the ramp up of existing customer volumes and additional volumes from new customers;
- increase of $33 million from our KMCC - Splitter due to the startup of the first and second phases in March 2015 and July 2015;
- increase of $44 million from our Double H pipeline which was acquired in February 2015 as part of the Hiland acquisition;
- increase of $35 million (40%) from Cochin driven by higher service revenues due to the completion of the Cochin Reversal project in the third quarter of 2014;
- increase of $23 million (7%) from our Pacific operations due to higher service revenues, resulting from higher volumes and margins; and
- increase of $8 million (33%) from our Transmix processing operations primarily due to favorable inventory adjustments impacting margins. The decrease in revenues of $490 million and associated decrease in costs of goods sold were caused by lower commodity prices.

Kinder Morgan Canada

	Year Ended December 31,		
	2016	2015	2014
	(In millions, except operating statistics)		
Revenues	$ 253	$ 260	$ 291
Operating expenses	(87)	(87)	(106)
Other income	—	1	—
Other, net	15	8	15
Segment EBDA(a)	$ 181	$ 182	$ 200
Change from prior period	Increase/(Decrease)		
Revenues	$ (7)	$ (31)	
Segment EBDA	$ (1)	$ (18)	
Transport volumes (MMBbl)(b)	115.2	115.4	106.8

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(a) Income tax expense that was allocated to and presented in Segment EBDA in prior periods is presented herein in income tax expense to conform to our current presentation as discussed above in "—Overview." The amounts for 2016, 2015 and 2014 were $20 million, $19 million and $18 million, respectively, in income tax expense.

(b) Represents Trans Mountain pipeline system volumes.

For the comparable years of 2016 and 2015, the Kinder Morgan Canada business segment had a decrease in Segment EBDA of $1 million (1%) and a decrease in revenues of $7 million (3%).

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Below are the changes in both Segment EBDA before certain items and revenues before certain items in 2015, when compared with 2014:

Year Ended December 31, 2015 versus Year Ended December 31, 2014

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	$(12)	(7)%	$ (30)	(11)%
Express Pipeline(a)	(6)	(100)%	n/a	n/a
Jet Fuel Pipeline	—	—%	(1)	(17)%
Total Kinder Morgan Canada	$(18)	(9)%	$ (31)	(11)%

n/a - not applicable

(a) Amount consists of unrealized foreign currency gains, net of book tax, on outstanding, short-term intercompany borrowings that were repaid in December 2014. We sold our debt and equity investments in Express Pipeline on March 14, 2013.

The changes in Segment EBDA for our Kinder Morgan Canada business segment are further explained by the significant factors driving Segment EBDA before certain items which factors include an unfavorable impact from foreign currency exchange rates, and repayment of the Express note as discussed in footnote (a) above.

General and Administrative, Interest, Corporate and Noncontrolling Interests

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
General and administrative expense(a)(e)	$669	$690	$610
Certain items(a)	5	(25)	28
Management fee reimbursement(e)	(34)	(37)	(36)
General and administrative expense before certain items	$640	$628	$602
Interest expense, net(b)	$1,806	$2,051	$1,798
Certain items(b)	193	27	3
Interest expense, net, before certain items	$1,999	$2,078	$1,801
Corporate(c)(e)	$(17)	$18	$(43)
Certain items(c)	8	(35)	22
Management fee revenue(e)	34	37	36
Corporate before certain items	$25	$20	$15
Net income (loss) attributable to noncontrolling interests	$13	$(45)	$1,417
Noncontrolling interests associated with certain items(d)	8	63	—
Net income attributable to noncontrolling interests before certain items	$21	$18	$1,417

Certain items

(a) 2016 amount includes increases in expense of (i) $14 million related to severance costs; and (ii) $12 million related to acquisition costs; offset by a decrease in expense of $31 million related to certain corporate litigation matters. 2015 and 2014 amounts include decreases in expense of $35 million and $39 million related to pension credit income. 2015 amount also includes increases in expense of $45 million related to certain corporate legal matters and $15 million related to costs associated with acquisitions. 2014 amount also includes a net increase of $11 million in expense for various other certain items.

(b) 2016, 2015 and 2014 amounts include (i) decreases in interest expense of $115 million, $71 million and $65 million, respectively, related to non-cash debt fair value adjustments associated with acquisitions; (ii) a $34 million decrease, a $21 million increase and a $15 million increase, respectively, in interest expense related to certain litigation matters; and (iii) a $44 million decrease, a $23 million increase and a $1 million decrease, respectively, in interest expense primarily related to non-cash true-ups of our estimates of swap ineffectiveness. 2014 amount also includes (i) increases in expense of $9 million of amortization of capitalized financing fees; (ii) $12 million of interest expense on margin for marketing contracts associated with legacy operations; and (iii) $27 million of interest expense related to the Merger Transactions.

(c) 2015 amount is primarily related to a litigation matter and 2014 amount is primarily related to our foreign operations.

(d) 2015 amount reflects the noncontrolling interest portion of certain items including (i) a $43 million impairment and a $6 million loss associated with Terminals segment certain items and disclosed above in "—Terminals" and (ii) a $14 million loss associated with a Natural Gas Pipelines segment impairment certain item and disclosed above in "—Natural Gas Pipelines."

Other

(e) 2016, 2015 and 2014 amounts include certain equity investee management fee revenue of $34 million, $37 million and $36 million, respectively. These amounts are recorded to the "Product sales and other" caption with the offsetting expenses primarily included in the "General and administrative" expense caption in our accompanying consolidated statements of income.

General and administrative expenses before certain items increased $12 million in 2016 and $26 million in 2015 when compared with the respective prior year. The increase in 2016 as compared to 2015 was primarily driven by higher benefit costs and lower capitalized costs partially offset by lower labor, outside services and insurance costs. The increase in 2015 as compared to 2014 was primarily driven by the acquisition of Hiland (effective February 13, 2015), lower capitalized costs and higher labor expenses partially offset by lower benefit and insurance costs.

In the table above, we report our interest expense as "net," meaning that we have subtracted interest income and capitalized interest from our total interest expense to arrive at one interest amount. Our consolidated interest expense net of interest income before certain items, decreased $79 million in 2016 and increased $277 million in 2015, respectively, when compared with the respective prior year. The decrease in interest expense in 2016 as compared to 2015 was primarily due to lower weighted average debt balances, partially offset by a slightly higher overall weighted average interest rate on our outstanding debt. The increase in 2015 as compared to 2014 was primarily due to higher weighted average debt balances as a result of capital expenditures, joint venture contributions and acquisitions that were made during 2014 and 2015, and incremental debt borrowings to fund the $3.9 billion cash portion of the Merger Transactions in November 2014.

We use interest rate swap agreements to convert a portion of the underlying cash flows related to our long-term fixed rate debt securities (senior notes) into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. As of December 31, 2016 and 2015, approximately 28% and 27%, respectively, of our debt balances (excluding debt fair value adjustments) were subject to variable interest rates-either as short-term or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swaps. For more information on our interest rate swaps, see Note 14 "Risk Management—Interest Rate Risk Management" to our consolidated financial statements.

After taking into effect the certain items, the Corporate expense for 2016 and 2015 increased by $5 million for each respective period when compared with the respective prior year.

Net income attributable to noncontrolling interests, represents the allocation of our consolidated net income attributable to all outstanding ownership interests in our consolidated subsidiaries that are not held by us. Net income attributable to noncontrolling interests before certain items for 2016 as compared to 2015 increased $3 million (17%). The $1,399 million decrease (99%) for 2015 as compared to 2014 was primarily due to our purchase of the KMP and EPB limited partner units and KMR shares formerly owned by the public in the fourth quarter of 2014 as part of the Merger Transactions.

Income Taxes

Year Ended December 31, 2016 versus Year Ended December 31, 2015

Our tax expense for the year ended December 31, 2016 is approximately $917 million, as compared with 2015 tax expense of $564 million. The $353 million increase in tax expense is primarily due to (i) an increase in our earnings as a result of lower impairments in 2016; (ii) the year over year increase in the deferred state tax expense as a result of our sale of a 50% interest in SNG in 2016 and the Hiland acquisition in 2015; and (iii) valuation allowances recorded in 2016 for foreign tax credits and capital loss carryforwards for which we do not expect to recognize any future tax benefits. These increases are partially offset by adjustments to our income tax reserve for uncertain tax positions.

Year Ended December 31, 2015 versus Year Ended December 31, 2014

Our tax expense for the year ended December 31, 2015 was $564 million, as compared with 2014 tax expense of $648 million. The $84 million decrease in tax expense is due primarily to (i) the tax impact of lower pretax earnings in 2015 primarily due to our recognition of $929 million of impairments on long-lived assets and investments and $1,150 million goodwill impairment of natural gas pipelines non-regulated midstream assets, of which $882 million is not tax deductible; (ii) the tax benefit of an increase in the deferred state tax rate as a result of the Hiland acquisition; (iii) the 2014 recording of a valuation allowance related to our investment in NGPL; and (iv) the elimination, as a result of the Merger Transactions, of the amortization of the deferred charge recorded as a result of the drop-downs of TGP, EPNG, and the midstream assets. These decreases are partially offset by the 2014 benefit of a worthless stock deduction related to our Brazil operations.

Liquidity and Capital Resources

General

As of December 31, 2016, we had $684 million of "Cash and cash equivalents," an increase of $455 million (199%) from December 31, 2015. We believe our cash position, remaining borrowing capacity on our credit facility (discussed below in "—Short-term Liquidity"), and our cash flows from operating activities are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations as discussed further below.

We have consistently generated substantial cash flow from operations, providing a source of funds of $4,787 million and $5,303 million in 2016 and 2015, respectively. The year-to-year decrease is discussed below in "Cash Flows—Operating Activities." We have relied on cash provided from operations to fund our operations as well as our debt service, sustaining capital expenditures, and dividend payments, and during 2016, to fund our expansion capital expenditures.

On September 1, 2016, we completed the sale of a 50% interest in our SNG natural gas pipeline system to Southern Company, receiving proceeds of approximately $1.4 billion. We used the proceeds from this transaction to reduce outstanding debt. In addition to repaying outstanding commercial paper and credit facility borrowings, proceeds from the sale were also used on September 30, 2016 to repay the $332 million principal amount of Copano's 7.125% notes due 2021, and on October 1, 2016, to repay the $749 million principal amount of Hiland's 7.25% senior notes due 2020 (see Note 9 "Debt"). As of September 1, 2016, SNG had $1,211 million of debt outstanding (including a current portion of $500 million) which is no longer consolidated on our balance sheet.

On August 16, 2016, CIG completed a private offering of $375 million in principal amount of 4.15% senior notes due August 15, 2026. We received net proceeds of $372 million from the offering and used the proceeds from the sale of the notes to reduce debt incurred as the result of the repayment of CIG's senior notes that matured in 2015 and for general corporate purposes.

On January 26, 2016, we announced the issuance of a new $1.0 billion term loan facility and the expansion of our revolving credit facility from $4.0 billion to $5.0 billion. The proceeds of the three-year unsecured term loan facility were used to refinance maturing long-term debt.

In general, we expect that our short-term liquidity needs will be met primarily through retained cash from operations, short-term borrowings or by issuing new long-term debt to refinance certain of our maturing long-term debt obligations. We also expect that our current common stock dividend level will allow us to use retained cash to fund our growth projects in 2017. Moreover, as a result of our current common stock dividend policy and by continuing to focus on high-grading our growth project backlog to allocate capital to the highest return opportunities, we do not expect to need to access the equity capital markets to fund our growth projects for the foreseeable future.

Credit Ratings and Capital Market Liquidity

We believe that our capital structure will continue to allow us to achieve our business objectives. We expect that our short-term liquidity needs will be met primarily through retained cash from operations or short-term borrowings.

However, over the long term, we are subject to uncertain capital market conditions and there can be no assurance we will be able or willing to access the public or private markets for equity and/or long-term senior notes in the future. If we were unable or unwilling to access the capital markets, we would be required to either continue utilizing internally generated cash, restrict expansion capital expenditures and/or potential future acquisitions or pursue debt financing alternatives, some of which could involve higher costs or negatively affect our and/or our subsidiaries' credit ratings.

As of December 31, 2016, our short-term corporate debt ratings were A-3, Prime-3 and F3 at Standard and Poor's, Moody's Investor Services and Fitch Ratings, Inc., respectively.

The following table represents KMI's and KMP's senior unsecured debt ratings as of December 31, 2016.

Rating agency	Senior debt rating	Date of last change	Outlook
Standard and Poor's	BBB-	November 20, 2014	Stable
Moody's Investor Services	Baa3	November 21, 2014	Stable
Fitch Ratings, Inc.	BBB-	November 20, 2014	Stable

Short-term Liquidity

As of December 31, 2016, our principal sources of short-term liquidity are (i) our $5.0 billion revolving credit facility and associated $4.0 billion commercial paper program; and (ii) cash from operations. The loan commitments under our revolving credit facility can be used for working capital and other general corporate purposes and as a backup to our commercial paper program. Borrowings under our commercial paper program and letters of credit reduce borrowings allowed under our credit facility. We provide for liquidity by maintaining a sizable amount of excess borrowing capacity under our credit facility and, as previously discussed, have consistently generated strong cash flows from operations.

As of December 31, 2016, our $2,696 million of short-term debt consisted primarily of senior notes that mature in 2017. We intend to refinance our short-term debt through credit facility borrowings, commercial paper borrowings, or by issuing new long-term debt or paying down short-term debt using cash retained from operations or received from asset sales. Our short-term debt balance as of December 31, 2015 was $821 million.

We had working capital (defined as current assets less current liabilities) deficits of $2,695 million and $1,241 million as of December 31, 2016 and 2015, respectively. Our current liabilities may include short-term borrowings used to finance our expansion capital expenditures, which we may periodically replace with long-term financing and/or partially pay down using retained cash from operations. The overall $1,454 million (117%) unfavorable change from year-end 2015 was primarily due to a net increase in our current portion of long-term debt, offset partially by a favorable change in cash. Generally, our working capital balance varies due to factors such as the timing of scheduled debt payments, timing differences in the collection and payment of receivables and payables, the change in fair value of our derivative contracts, and changes in our cash and cash equivalent balances as a result of excess cash from operations after payments for investing and financing activities (discussed below in "—Long-term Financing" and "— Capital Expenditures").

We employ a centralized cash management program for our U.S.-based bank accounts that concentrates the cash assets of our wholly owned subsidiaries in joint accounts for the purpose of providing financial flexibility and lowering the cost of borrowing. These programs provide that funds in excess of the daily needs of our wholly owned subsidiaries are concentrated, consolidated or otherwise made available for use by other entities within the consolidated group. We place no material restrictions on the ability to move cash between entities, payment of intercompany balances or the ability to upstream dividends to KMI other than restrictions that may be contained in agreements governing the indebtedness of those entities.

Certain of our wholly owned subsidiaries are subject to FERC-enacted reporting requirements for oil and natural gas pipeline companies that participate in cash management programs. FERC-regulated entities subject to these rules must, among other things, place their cash management agreements in writing, maintain current copies of the documents authorizing and supporting their cash management agreements, and file documentation establishing the cash management program with the FERC.

Long-term Financing

Our equity consists of Class P common stock and mandatory convertible preferred stock each with a par value of $0.01 per share. In 2015, through an equity distribution agreement, we issued and sold through or to our sales agents and/or principals shares of our Class P common stock. For more information on our equity issuances during 2015 and our equity distribution agreement, see Note 11, "Stockholders' Equity" to our consolidated financial statements.

From time to time, we issue long-term debt securities, often referred to as senior notes. All of our senior notes issued to date, other than those issued by certain of our subsidiaries, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. All of our fixed rate senior notes provide that the notes may be redeemed at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date, and, in most cases, plus a make-whole premium. In addition, from time to time our subsidiaries, have issued long-term debt securities. Furthermore, we and almost all of our direct and indirect wholly owned domestic subsidiaries are parties to a cross guaranty wherein we each guarantee the debt of each other. See Note 19 “Guarantee of Securities of Subsidiaries” to our consolidated financial statements. As of December 31, 2016 and 2015, the aggregate principal amount outstanding of our various long-term debt obligations (excluding current maturities) was $36,205 million and $40,732 million, respectively. For more information regarding our debt-related transactions in 2016, see Note 9 “Debt” to our consolidated financial statements.

We achieve our variable rate exposure primarily by issuing long-term fixed rate debt and then swapping the fixed rate interest payments for variable rate interest payments and through the issuance of commercial paper or credit facility borrowings.

To date, our debt balances have not adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. For additional information about our debt-related transactions in 2016, see Note 9 “Debt” to our consolidated financial statements. For information about our interest rate risk, see Item 7A “Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk.”

Capital Expenditures

We account for our capital expenditures in accordance with GAAP. We also distinguish between capital expenditures that are maintenance/sustaining capital expenditures and those that are expansion capital expenditures (which we also refer to as discretionary capital expenditures). Expansion capital expenditures are those expenditures which increase throughput or capacity from that which existed immediately prior to the addition or improvement, and are not deducted in calculating DCF (see “Results of Operations—Distributable Cash Flow”). With respect to our oil and gas producing activities, we classify a capital expenditure as an expansion capital expenditure if it is expected to increase capacity or throughput (i.e. production capacity) from the capacity or throughput immediately prior to the making or acquisition of such additions or improvements. Maintenance capital expenditures are those which maintain throughput or capacity. The distinction between maintenance and expansion capital expenditures is a physical determination rather than an economic one, irrespective of the amount by which the throughput or capacity is increased.

Budgeting of maintenance capital expenditures is done annually on a bottom-up basis. For each of our assets, we budget for and make those maintenance capital expenditures that are necessary to maintain safe and efficient operations, meet customer needs and comply with our operating policies and applicable law. We may budget for and make additional maintenance capital expenditures that we expect to produce economic benefits such as increasing efficiency and/or lowering future expenses. Budgeting and approval of expansion capital expenditures are generally made periodically throughout the year on a project-by-project basis in response to specific investment opportunities identified by our business segments from which we generally expect to receive sufficient returns to justify the expenditures. Generally, the determination of whether a capital expenditure is classified as maintenance/sustaining or as expansion capital expenditures is made on a project level. The classification of our capital expenditures as expansion capital expenditures or as maintenance capital expenditures is made consistent with our accounting policies and is generally a straightforward process, but in certain circumstances can be a matter of management judgment and discretion . The classification has an impact on DCF because capital expenditures that are classified as expansion capital expenditures are not deducted from DCF, while those classified as maintenance capital expenditures are. See “—Common Dividends” and “—Preferred Dividends”

Our capital expenditures for the year ended December 31, 2016, and the amount we expect to spend for 2017 to sustain and grow our business are as follows (in millions):

	2016	Expected 2017
Sustaining capital expenditures(a)	$540	$ 630
Discretionary capital expenditures(b)(c)	$2,807	$ 3,240

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(a)

2016 and Expected 2017 amounts include $90 million and $112 million, respectively, for our proportionate share of sustaining capital expenditures of certain unconsolidated joint ventures.

(b) 2016 amount includes $574 million of discretionary capital expenditures of unconsolidated joint ventures and small acquisitions (i.e. excludes Hiland acquisition) and divestitures and excludes a combined $199 million of net changes from accrued capital expenditures and contractor retainage.

(c) Expected 2017 amount includes our contributions to certain unconsolidated joint ventures and small acquisitions and divestitures, net of contributions estimated from unaffiliated joint venture partners for consolidated investments.

Off Balance Sheet Arrangements

We have invested in entities that are not consolidated in our financial statements. For information on our obligations with respect to these investments, as well as our obligations with respect to related letters of credit, see Note 13 “Commitments and Contingent Liabilities” to our consolidated financial statements. Additional information regarding the nature and business purpose of our investments is included in Note 7 “Investments” to our consolidated financial statements.

Contractual Obligations and Commercial Commitments

	Payments due by period				
	Total	Less than 1 year	2-3 years	4-5 years	More than 5 years
	(In millions)				
Contractual obligations:					
Debt borrowings-principal payments(a)	$38,901	$ 2,696	$6,148	$4,626	$ 25,431
Interest payments(b)	26,441	2,026	3,644	3,154	17,617
Leases and rights-of-way obligations(c)	764	106	180	136	342
Pension and postretirement welfare plans(d)	970	38	34	35	863
Transportation, volume and storage agreements(e)	1,106	169	302	261	374
Other obligations(f)	307	70	94	42	101
Total	$68,489	$ 5,105	$10,402	$8,254	$ 44,728
Other commercial commitments:					
Standby letters of credit(g)	$219	$ 199	$20	$—	$ —
Capital expenditures(h)	$1,112	$ 1,112	$—	$—	$ —

(a) Less than 1 year amount primarily includes $2,541 million of current maturities on senior notes and $111 million associated with our Trust I Preferred Securities that are classified as current obligations because these securities have rights to convert into cash, KMI common stock and/or warrants. See Note 9 “Debt” to our consolidated financial statements.

(b) Interest payment obligations exclude adjustments for interest rate swap agreements and assume no change in variable interest rates from those in effect at December 31, 2016.

(c) Represents commitments pursuant to the terms of operating lease agreements and liabilities for rights-of-way.

(d) Represents the amount by which the benefit obligations exceeded the fair value of fund assets for pension and other postretirement benefit plans at year-end. The payments by period include expected contributions to funded plans in 2017 and estimated benefit payments for unfunded plans in all years.

(e) Primarily represents transportation agreements of $469 million, volume agreements of $434 million and storage agreements for capacity on third party and an affiliate pipeline systems of $147 million.

(f) Primarily includes environmental liabilities related to sites that we own or have a contractual or legal obligation with a regulatory agency or property owner upon which we will perform remediation activities. These liabilities are included within “Other long-term liabilities and deferred credits” in our consolidated balance sheets.

(g) The $219 million in letters of credit outstanding as of December 31, 2016 consisted of the following (i) $50 million under twelve letters of credit for insurance purposes; (ii) a $32 million letter of credit supporting our pipeline and terminal operations in Canada; (iii) our $30 million guarantee under letters of credit totaling $46 million supporting our International Marine Terminals Partnership Plaquemines, Louisiana Port, Harbor, and Terminal Revenue Bonds; (iv) a $25 million letter of credit supporting our Kinder Morgan Liquids Terminals LLC New Jersey Economic Development Revenue Bonds; (v) a $24 million letter of credit supporting our Kinder Morgan Operating L.P. “B” tax-exempt bonds; (vi) a $10 million letter of credit supporting Nassau County, Florida Ocean Highway and Port Authority tax-exempt bonds; and (vii) a combined $32 million in twenty-four letters of credit supporting environmental, power and marketing purposes, and other obligations of us and our subsidiaries.

(h)

Represents commitments for the purchase of plant, property and equipment as of December 31, 2016 and obligations for the definitive construction agreement with Philly Tankers LLC for 2017.

Cash Flows

Operating Activities

The net decrease of $516 million (10%) in cash provided by operating activities in 2016 compared to 2015 was primarily attributable to:

- a $414 million decrease in cash from overall net income after adjusting our period-to-period $513 million increase in net income for non-cash items primarily consisting of the following: (i) loss on impairment of goodwill; (ii) net losses on impairments and divestitures; (iii) losses on impairment and divestitures of equity investments; (iv) gains on early extinguishment of debt; (See discussion above in "—Results of Operations" for further information regarding these items); (v) DD&A expenses (including amortization of excess cost of equity investments); (vi) deferred income taxes; and (vii) equity earnings from our equity investments; and
- a $102 million decrease in cash associated with net changes in working capital items and other non-current assets and liabilities. The decrease was driven, among other things, primarily by a $195 million income tax refund received in 2015, and lower cash flow due to unfavorable changes in the collection of trade and exchange gas receivables. These decreases were offset partially by higher cash flows associated with the timing of payments from our trade payables.

Investing Activities

The $4,001 million net decrease in cash used in investing activities in 2016 compared to 2015 was primarily attributable to:

- a $1,746 million decrease in expenditures for acquisitions and investments in 2016 compared to the respective 2015 period. The overall decrease in acquisitions was primarily related to the $324 million portion of the purchase price we paid in 2016 for the BP terminals acquisition, versus the $1,706 million (net of cash assumed) and $158 million we paid for the Hiland and Vopak acquisitions, respectively, and the $134 million we paid to increase our ownership in NGPL Holdings LLC to 50% in the 2015 period;
- a $1,401 million net increase in cash due to proceeds from the sale of a 50% equity interest in SNG;
- a $1,014 million reduction in capital expenditures; and
- a $291 million increase in cash due to an increase in proceeds from sales of other long-lived assets; partially offset by,
- a $312 million increase in contributions to equity investments in 2016 compared to 2015, primarily due to a $312 million contribution to our 50% investment in NGPL Holdings LLC in 2016; and
- a $142 million decrease in Other, net primarily due to unfavorable changes in restricted deposits associated with our hedging activities.

Financing Activities

The net decrease of $2,956 million in cash provided by financing activities in 2016 compared to 2015 was primarily attributable to:

- a $3,870 million decrease in financing activities resulting from the issuances of our Class P shares under our equity distribution agreement in 2015 with no Class P Share issuance activity in 2016;
- a $1,541 million decrease in financing activities due to the issuance of our mandatory convertible preferred stock in 2015;
- a $626 million decrease in net debt proceeds. See Note 9 "Debt" for further information regarding our debt activity; and
- a $154 million increase in dividends paid to our mandatory convertible preferred shareholders in 2016;

partially offset by,

- a $3,106 million reduction in dividend payments paid to our common shareholders; and
- a $106 million increase in contributions provided by noncontrolling interests, primarily reflecting the contributions received from BP for its 25% share of a newly formed joint venture.

Common Dividends

The table below reflects the payment of cash dividends of $0.50 per common share for 2016.

Three months ended	Total quarterly dividend per share for the period	Date of declaration	Date of record	Date of dividend
March 31, 2016	$ 0.125	April 20, 2016	May 2, 2016	May 16, 2016
June 30, 2016	$ 0.125	July 20, 2016	August 1, 2016	August 15, 2016
September 30, 2016	$ 0.125	October 19, 2016	November 1, 2016	November 15, 2016
December 31, 2016	$ 0.125	January 18, 2017	February 1, 2017	February 15, 2017

The actual amount of common dividends to be paid on our capital stock will depend on many factors, including our financial condition and results of operations, liquidity requirements, business prospects, capital requirements, legal, regulatory and contractual constraints, tax laws, Delaware laws and other factors. See Item 1A. “Risk Factors—The guidance we provide for our anticipated dividends is based on estimates. Circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business.” All of these matters will be taken into consideration by our board of directors in declaring dividends.

Our common stock dividends are not cumulative. Consequently, if dividends on our common stock are not paid at the intended levels, our common stockholders are not entitled to receive those payments in the future. Our common stock dividends generally will be paid on or about the 15th day of each February, May, August and November.

Preferred Dividends

Dividends on our mandatory convertible preferred stock are payable on a cumulative basis when, as and if declared by our board of directors (or an authorized committee thereof) at an annual rate of 9.750% of the liquidation preference of $1,000 per share on January 26, April 26, July 26 and October 26 of each year, commencing on January 26, 2016 to, and including, October 26, 2018. We may pay dividends in cash or, subject to certain limitations, in shares of common stock or any combination of cash and shares of common stock. The terms of the mandatory convertible preferred stock provide that, unless full cumulative dividends have been paid or set aside for payment on all outstanding mandatory convertible preferred stock for all prior dividend periods, no dividends may be declared or paid on common stock.

Period	Total dividend per share for the period	Date of declaration	Date of record	Date of dividend
January 26, 2016 through April 25, 2016	$ 24.375	January 20, 2016	April 11, 2016	April 26, 2016
April 26, 2016 through July 25, 2016	$ 24.375	April 20, 2016	July 11, 2016	July 26, 2016
July 26, 2016 through October 25, 2016	$ 24.375	July 20, 2016	October 11, 2016	October 26, 2016
October 26, 2016 through January 25, 2017	$ 24.375	October 19, 2016	January 11, 2017	January 26, 2017

The cash dividend of $24.375 per share of our mandatory convertible preferred stock is equivalent to $1.21875 per depository share.

Recent Accounting Pronouncements

Please refer to Note 18 “Recent Accounting Pronouncements” to our consolidated financial statements for information concerning recent accounting pronouncements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Generally, our market risk sensitive instruments and positions have been determined to be "other than trading." Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in energy commodity prices or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in energy commodity prices or interest rates and the timing of transactions.

Energy Commodity Market Risk

We are exposed to energy commodity market risk and other external risks in the ordinary course of business. However, we manage these risks by executing a hedging strategy that seeks to protect us financially against adverse price movements and serves to minimize potential losses. Our strategy involves the use of certain energy commodity derivative contracts to reduce and minimize the risks associated with unfavorable changes in the market price of natural gas, NGL and crude oil. The derivative contracts that we use include energy products traded on the NYMEX and OTC markets, including, but not limited to, futures and options contracts, fixed price swaps and basis swaps. In addition, prior to May 2016, we had power forward and swap contracts related to legacy operations of acquired businesses.

Our hedging strategy involves entering into a financial position intended to offset our physical position, or anticipated position, in order to minimize the risk of financial loss from an adverse price change. For example, as sellers of crude oil and natural gas, we often enter into fixed price swaps and/or futures contracts to guarantee or lock-in the sale price of our crude oil or the margin from the sale and purchase of our natural gas at the time of market delivery, thereby in whole or in part offsetting any change in prices, either positive or negative.

Our policies require that derivative contracts are only entered into with carefully selected major financial institutions or similar counterparties based upon their credit ratings and other factors, and we maintain strict dollar and term limits that correspond to our counterparties' credit ratings. While it is our policy to enter into derivative transactions principally with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that losses will result from counterparty credit risk in the future.

The credit ratings of the primary parties from whom we transact in energy commodity derivative contracts (based on contract market values) are as follows (credit ratings per Standard & Poor's Rating Service):

	Credit Rating
Bank of America / Merrill Lynch	BBB+
Societe Generale	A
J Aron / Goldman Sachs	BBB+
Bank of Nova Scotia	A+
J.P. Morgan	A-

As discussed above, the principal use of energy commodity derivative contracts is to mitigate the market price risk associated with anticipated transactions for the purchase and sale of natural gas, NGL and crude oil. Using derivative contracts for this purpose helps provide increased certainty with regard to operating cash flows which helps us to undertake further capital improvement projects, attain budget results and meet dividend targets. We may categorize such use of energy commodity derivative contracts as cash flow hedges because the derivative contract is used to hedge the anticipated future cash flow of a transaction that is expected to occur but which value is uncertain.

We measure the risk of price changes in the natural gas, NGL and crude oil derivative instruments portfolios utilizing a sensitivity analysis model. The sensitivity analysis applied to each portfolio measures the potential income or loss (i.e., the change in fair value of the derivative instrument portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values. A hypothetical 10% movement in the underlying commodity prices would have the following effect on the associated derivative contracts' estimated fair value (in millions):

	As of December 31,

Commodity derivative	2016	2015
Crude oil	$117	$97
Natural gas	16	13
NGL	11	4
Total	$144	$114

As discussed above, we enter into derivative contracts largely for the purpose of mitigating the risks that accompany certain of our business activities and, therefore both in the sensitivity analysis model and in reality, the change in the market value of the derivative contracts' portfolio is offset largely by changes in the value of the underlying physical transactions.

Our sensitivity analysis represents an estimate of the reasonably possible gains and losses that would be recognized on the natural gas, NGL and crude oil portfolios of derivative contracts assuming hypothetical movements in future market rates and is not necessarily indicative of actual results that may occur. It does not represent the maximum possible loss or any expected loss that may occur, since actual future gains and losses will differ from those estimated. Actual gains and losses may differ from estimates due to actual fluctuations in market rates, operating exposures and the timing thereof, as well as changes in our portfolio of derivatives during the year.

Interest Rate Risk

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. The market risk inherent in our debt instruments and positions is the potential change arising from increases or decreases in interest rates as discussed below.

For fixed rate debt, changes in interest rates generally affect the fair value of the debt instrument, but not our earnings or cash flows. Conversely, for variable rate debt, changes in interest rates generally do not impact the fair value of the debt instrument, but may affect our future earnings and cash flows. Generally, there is not an obligation to prepay fixed rate debt prior to maturity and, as a result, changes in fair value should not have a significant impact on the fixed rate debt. We are generally subject to interest rate risk upon refinancing maturing debt. Below are our debt balances and sensitivity to interest rates (in millions):

	December 31, 2016		December 31, 2015	
	Carrying value	Estimated fair value(c)	Carrying value	Estimated fair value(c)
Fixed rate debt(a)	$38,861	$ 39,854	$43,039	$ 37,329
Variable rate debt	$1,189	$ 1,161	$188	$ 152
Notional principal amount of fixed-to-variable interest rate swap agreements	9,775		11,000	
Debt subject to variable interest rates(b)	$10,964		$11,188	

____

(a) A hypothetical 10% change in the average interest rates applicable to such debt as of December 31, 2016 and 2015, would result in changes of approximately $1,527 million and $1,667 million, respectively, in the fair values of these instruments.

(b) A hypothetical 10% change in the weighted average interest rate on all of our borrowings (approximately 50 basis points in 2016 and approximately 49 basis points in 2015) when applied to our outstanding balance of variable rate debt as of December 31, 2016 and 2015, including adjustments for the notional swap amounts described above, would result in changes of approximately $54 million and $55 million, respectively, in our 2016 and 2015 annual pre-tax earnings.

(c) Fair values were determined using quoted market prices, where applicable, or future cash flows discounted at market rates for similar types of borrowing arrangements.

Fixed-to-variable interest rate swap agreements are entered into for the purpose of converting a portion of the underlying cash flows related to long-term fixed rate debt securities into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. Since the fair value of fixed rate debt varies with changes in the market rate of interest, swap agreements are entered into to receive a fixed and pay a variable rate of interest. Such swap agreements result in future cash flows that vary with the market rate of interest, and therefore hedge against changes in the fair value of the fixed rate debt due to market rate changes.

We monitor the mix of fixed rate and variable rate debt obligations in light of changing market conditions and from time to time, may alter that mix by, for example, refinancing outstanding balances of variable rate debt with fixed rate debt (or vice versa) or by entering into interest rate swap agreements or other interest rate hedging agreements. As of December 31, 2016, including debt converted to variable rates through the use of interest rate swaps but excluding our debt fair value adjustments, approximately 28% of our debt balances were subject to variable interest rates.

For more information on our interest rate risk management and on our interest rate swap agreements, see Note 14 “Risk Management” to our consolidated financial statements.

Foreign Currency Risk

In connection with the issuance of our Euro denominated senior notes in March 2015, we entered into $1,358 million of cross-currency swap agreements that effectively convert all of our fixed rate Euro denominated debt, including annual interest payments and the payment of principal at maturity, to U.S. dollar denominated debt at fixed rates. These swaps eliminate the foreign currency risk associated with our foreign currency denominated debt.

Item 8. Financial Statements and Supplementary Data.

The information required in this Item 8 is in this report as set forth in the “Index to Financial Statements” on page 73.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2016, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management’s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an assessment of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management concluded that our internal control over financial reporting was effective as of December 31, 2016.

The effectiveness of our internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their audit report, which appears herein.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2016 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.
The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2017 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2017.

Item 11. Executive Compensation.
The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2017 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2017.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2017 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2017.

Item 13. Certain Relationships and Related Transactions, and Director Independence.
The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2017 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2017.

Item 14. Principal Accounting Fees and Services.

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2017 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2017.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements and (2) Financial Statement Schedules
See "Index to Financial Statements" set forth on Page 73.

(3) Exhibits

Exhibit Number	Description
2.1 *	Agreement and Plan of Merger, dated as of August 9, 2014, by and among Kinder Morgan Energy Partners, L.P., Kinder Morgan G.P., Inc., Kinder Morgan Management, LLC, Kinder Morgan, Inc. (KMI) and P Merger Sub LLC (schedules omitted pursuant to Item 601(b)(2) of Regulation S-K) (filed as Exhibit 2.1 to KMI's Current Report on Form 8-K, filed August 12, 2014 (File No. 001-35081))
2.2 *	Agreement and Plan of Merger, dated as of August 9, 2014, by and among Kinder Morgan Management, LLC, KMI, and R Merger Sub LLC (schedules omitted pursuant to Item 601(b)(2) of Regulation S-K) (filed as Exhibit 2.2 to KMI's Current Report on Form 8-K, filed August 12, 2014 (File No. 001-35081))
2.3 *	Agreement and Plan of Merger, dated as of August 9, 2014, by and among El Paso Pipeline Partners, L.P., El Paso Pipeline GP Company, L.L.C., KMI, and E Merger Sub LLC (schedules omitted pursuant to Item 601(b)(2) of Regulation S-K) (filed as Exhibit 2.3 to KMI's Current Report on Form 8-K, filed August 12, 2014 (File No. 001-35081))
3.1 *	

	Amended and Restated Certificate of Incorporation of KMI (filed as Exhibit 3.1 to KMI's Quarterly Report on Form 10-Q for the three months ended June 30, 2015 (File No. 001-35081))
3.2*	Amended and Restated Bylaws of KMI (filed as Exhibit 3.1 to KMI's Current Report on Form 8-K, filed January 24, 2017 (File No. 001-35081))
3.3*	Certificate of Designations of KMI 9.75% Series A Mandatory Convertible Preferred Stock, par value $0.01 per share (KMI Preferred Stock) (filed as Exhibit 3.1 to KMI's Current Report on Form 8-K filed October 30, 2015 (File No. 001-35081))

Exhibit Number		Description
4.1	*	Form of certificate representing Class P common shares of KMI (filed as Exhibit 4.1 to KMI's Registration Statement on Form S-1 filed on January 18, 2011 (File No. 333-170773))
4.2	*	Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.2 to KMI's Quarterly Report on Form 10-Q for the three Months ended March 31, 2011 (File No. 001-35081))
4.3	*	Amendment No. 1 to the Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.3 to KMI's Current Report on Form 8-K filed on May 30, 2012 (File No. 001-35081))
4.4	*	Amendment No. 2 to the Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.1 to KMI's Current Report on Form 8-K filed on December 3, 2014 (File No. 001-35081))
4.5	*	Warrant Agreement, dated as of May 25, 2012, among KMI, Computershare Trust Company, N.A. and Computershare Inc., as Warrant Agent (filed as Exhibit 4.1 to KMI's Current Report on Form 8-K filed on May 30, 2012 (File No. 001-35081))
4.6	*	Form of certificate for KMI Preferred Stock (included as Exhibit A to Exhibit 3.1 to KMI's Current Report on Form 8-K filed October 30, 2015 (File No. 001-35081))
4.7	*	Deposit Agreement, dated as of October 30, 2015, between KMI and Computershare Inc. and Computershare Trust Company, N.A., as joint depositary, on behalf of all holders from time to time of the depositary receipts issued thereunder (filed as Exhibit 4.2 to KMI's Current Report on Form 8-K filed October 30, 2015 (File No. 001-35081))
4.8	*	Form of Depositary Receipt for depositary shares, each representing 1/20th of a share of KMI Preferred Stock (included as Exhibit A to Exhibit 4.2 to KMI's Current Report on Form 8-K filed October 30, 2015 (File No. 001-35081))
4.9	*	Form of Senior Indenture between Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102963))
4.10	*	Form of Senior Note of Kinder Morgan Kansas, Inc. (included in the Form of Senior Indenture filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102963))
4.11	*	Indenture dated as of December 9, 2005, among Kinder Morgan Finance Company LLC (formerly Kinder Morgan Finance Company, ULC), Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 15, 2005 (File No. 1-06446))
4.12	*	Forms of Kinder Morgan Finance Company LLC Notes (included in the Indenture filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 15, 2005 (File No. 1-06446))
4.13	*	Indenture dated January 2, 2001 between Kinder Morgan Energy Partners, L.P. and First Union National Bank, as trustee, relating to Senior Debt Securities (including form of Senior Debt Securities) (filed as Exhibit 4.11 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2000 (File No. 1-11234))

4.14*	Certificate of Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 7.40% Notes due March 15, 2031 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed on March 14, 2001 (File No. 1-11234))
4.15*	Specimen of 7.40% Notes due March 15, 2031 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed on March 14, 2001(File No. 1-11234))
4.16*	Certificate of Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 7.750% Notes due March 15, 2032 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234))
4.17*	Specimen of 7.750% Notes due March 15, 2032 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234))

Exhibit Number	Description
4.18*	Indenture dated August 19, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
4.19*	First Supplemental Indenture to Indenture dated August 19, 2002, dated August 23, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
4.20*	Form of 7.30% Notes due 2033 (contained in the Indenture filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
4.21*	Senior Indenture dated January 31, 2003 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961))
4.22*	Form of Senior Note of Kinder Morgan Energy Partners, L.P. (included in the Form of Senior Indenture filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961))
4.23*	Certificate of Vice President, Treasurer and Chief Financial Officer and Vice President, General Counsel and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 5.80% Notes due March 15, 2035 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 (File No. 1-11234))
4.24*	Certificate of Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 6.00% Senior Notes due 2017 and 6.50% Senior Notes due 2037 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 1-11234))
4.25*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 6.95% Senior Notes due 2038 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 (File No. 1-11234))
4.26*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.95% Senior Notes due 2018 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2007 (File No. 1-11234))
4.27*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 9.00% Senior Notes due 2019 (filed as Exhibit 4.29 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 1-11234))
4.28*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P.,

	establishing the terms of the 6.85% Senior Notes due 2020 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2009 (File No. 1-11234))
4.29*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.80% Senior Notes due 2021, and the 6.50% Senior Notes due 2039 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2009 (File No. 1-11234))
4.30*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.30% Senior Notes due 2020, and the 6.55% Senior Notes due 2040 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 (File No. 1-11234))
4.31*	Indenture, dated December 20, 2010, among Kinder Morgan Finance Company LLC, Kinder Morgan Kansas, Inc. and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 23, 2010 (File No. 1-06446))

Exhibit Number	Description
4.32*	Officers' Certificate establishing the terms of the 6.000% Senior Notes due 2018 of Kinder Morgan Finance Company LLC (with the form of note attached thereto) (filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 23, 2010 (File No. 1-06446))
4.33*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 6.375% Senior Notes due 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 1-11234))
4.34*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.150% Senior Notes due 2022, and the 5.625% Senior Notes due 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 1-11234))
4.35*	Certificate of the Vice President, Finance and Investor Relations and the Vice President and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 3.500% Senior Notes due 2021 and the 5.500% Senior Notes due 2044 (Filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2014 (File No. 1-11234))
4.36*	Certificate of the Vice President and Treasurer and the Vice President and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.250% Senior Notes due 2024 and the 5.400% Senior Notes due 2044 (Filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2014 (File No. 1-11234))
4.37*	Indenture, dated March 1, 2012, among KMI and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to KMI's Registration Statement on Form S-3 filed on March 1, 2012 (File No. 001-35081))
4.38*	Certificate of the Vice President and Treasurer and the Vice President and Secretary of KMI establishing the terms of the 2.000% Senior Notes due 2017, the 3.050% Senior Notes due 2019, the 4.300% Senior Notes due 2025, the 5.300% Senior Notes due 2034 and the 5.550% Senior Notes due 2045 (filed as Exhibit 10.53 to KMI's Annual Report on Form 10-K for the year ended December 31, 2014 (File No. 001-35081))
4.39*	Certificate of Vice President and Treasurer and Vice President and Secretary of KMI establishing the terms of the 5.050% Senior Notes due 2046 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the three months ended March 31, 2015 (File No. 001-35081))
4.40*	Certificate of Vice President and Treasurer and Vice President and Secretary of KMI establishing the terms of the 1.500% Senior Notes due 2022 and 2.250% Senior Notes due 2027 (filed as Exhibit 4.2 to KMI's Form 8-A, filed March 16, 2015 and incorporated herein by reference (File No. 001-35081))
4.41	Certain instruments with respect to long-term debt of KMI and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of KMI and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4) (iii) (A) of Regulation S-K, 17 C.F.R. sec. #229.601. KMI hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.

10.1*	KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 4.5 to KMI’s Registration Statement on Form S-8, filed on July 1, 2015, and incorporated herein by reference (File No. 333-205430))
10.2*	Amendment No. 1 to KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 10.2 to KMI’s Current Report on Form 8-K filed on January 24, 2017 (File No. 001-35081))
10.3*	2015 Form of Employee Restricted Stock Unit Agreement (filed as Exhibit 4.6 to KMI’s Registration Statement on Form S-8, filed on July 1, 2015, and incorporated herein by reference (File No. 333-205430))
10.4*	2016 Form of Employee Restricted Stock Unit Agreement (filed as Exhibit 10.2 to KMI’s Quarterly Report on Form 10-Q for the three months ended June 30, 2016 (File No. 001-35081))
10.5*	Amended and Restated Stock Compensation Plan for Non-Employee Directors (filed as Exhibit 10.5 to KMI’s Quarterly Report on Form 10-Q for the three months ended June 30, 2015 (File No. 001-35081))
10.6*	2015 Form of Non-Employee Director Stock Compensation Agreement (filed as Exhibit 10.6 to KMI’s Quarterly Report on Form 10-Q for the three months ended June 30, 2015 (File No. 001-35081))

Exhibit Number		Description
10.7	*	2011 Form of Non-Employee Director Stock Compensation Agreement (filed as Exhibit 10.3 to KMI's Quarterly Report on Form 10-Q for the three months ended March 31, 2011 (File No. 001-35081))
10.8	*	KMI Employees Stock Purchase Plan (filed as Exhibit 10.5 to KMI's Quarterly Report on Form 10-Q for the three months ended March 31, 2011 (File No. 001-35081))
10.9	*	Amended and Restated Annual Incentive Plan of KMI (filed as Exhibit 10.4 to KMI's Quarterly Report on Form 10-Q for the three months ended June 30, 2015 (File No. 001-35081))
10.10	*	Amendment No. 1 to Amended and Restated Incentive Plan of KMI (filed as Exhibit 10.1 to KMI's Current Report on Form 8-K filed January 24, 2017 (File No. 001-35081))
10.11	*	Support Agreement, dated as of August 9, 2014, by and among Kinder Morgan Energy Partners, L.P., Kinder Morgan G.P., Inc., Kinder Morgan Management, LLC, El Paso Pipeline Partners, L.P., El Paso Pipeline GP Company, L.L.C., Richard D. Kinder and RDK Investments, Ltd. (filed as Exhibit 10.1 to KMI's Current Report on Form 8-K filed August 12, 2014 (File No. 001-35081))
10.12	*	Bridge Credit Agreement, dated September 19, 2014 among KMI, as borrower, Barclays Bank PLC, as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to KMI's Current Report on Form 8-K filed September 25, 2014 (File No. 001-35081))
10.13	*	Revolving Credit Agreement, dated September 19, 2014 among KMI, as borrower, Barclays Bank PLC, as administrative agent, and the lenders and issuing banks party thereto (filed as Exhibit 10.2 to KMI's Current Report on Form 8-K filed September 25, 2014(File No. 001-35081))
10.14	*	Term Loan Agreement, dated as of January 26, 2016 among KMI, as borrower, the lenders party thereto and Barclays Bank PLC, as administrative agent (filed as exhibit 10.2 to KMI's Quarterly Report on Form 10-Q for the three months ended March 31, 2016 (File No. 001-35081))
10.15	*	Joinder Agreement, dated as of January 26, 2016, to KMI's Revolving Credit Agreement, dated as of September 19, 2014 among KMI, the lenders party thereto and Barclay Bank PLC, as administrative agent. (filed as exhibit 10.3 to KMI's Quarterly Report on Form 10-Q for the three months ended March 31, 2016 (File No. 001-35081))
10.16		Cross Guarantee Agreement, dated as of November 26, 2014 among KMI and certain of its subsidiaries with schedules updated as of December 31, 2016
12.1		Statement re: computation of ratio of earnings to fixed charges
21.1		Subsidiaries of KMI
23.1		Consent of PricewaterhouseCoopers LLP
31.1		Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2		Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
95.1	Mine Safety Disclosures
101	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the years ended December 31, 2016, 2015, and 2014; (ii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2016, 2015, and 2014; (iii) our Consolidated Balance Sheets as of December 31, 2016 and 2015; (iv) our Consolidated Statements of Cash Flows for the years ended December 31, 2016, 2015, and 2014; (v) our Consolidated Statement of Stockholders' Equity as of and for the years ended December 31, 2016, 2015, and 2014; and (vi) the notes to our Consolidated Financial Statements

*Asterisk indicates exhibits incorporated by reference as indicated; all other exhibits are filed herewith, except as noted otherwise.

KINDER MORGAN, INC. AND SUBSIDIARIES
INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Kinder Morgan, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of comprehensive income, of stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Kinder Morgan, Inc. and its subsidiaries (the "Company") at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing in Item 9A of the Company's 2016 Annual Report on Form 10-K. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 10, 2017

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In Millions, Except Per Share Amounts)

	Year Ended December 31,		
	2016	2015	2014
Revenues			
Natural gas sales	$2,454	$2,839	$4,115
Services	8,146	8,290	7,650
Product sales and other	2,458	3,274	4,461
Total Revenues	13,058	14,403	16,226
Operating Costs, Expenses and Other			
Costs of sales	3,498	4,115	6,278
Operations and maintenance	2,303	2,337	2,157
Depreciation, depletion and amortization	2,209	2,309	2,040
General and administrative	669	690	610
Taxes, other than income taxes	421	439	418
Loss on impairment of goodwill	—	1,150	—
Loss on impairments and divestitures, net	387	919	274
Other (income) expense, net	(1)	(3)	1
Total Operating Costs, Expenses and Other	9,486	11,956	11,778
Operating Income	3,572	2,447	4,448
Other Income (Expense)			
Earnings from equity investments	497	414	406
Loss on impairments and divestitures of equity investments, net	(610)	(30)	—
Amortization of excess cost of equity investments	(59)	(51)	(45)
Interest, net	(1,806)	(2,051)	(1,798)
Other, net	44	43	80
Total Other Expense	(1,934)	(1,675)	(1,357)
Income Before Income Taxes	1,638	772	3,091
Income Tax Expense	(917)	(564)	(648)
Net Income	721	208	2,443
Net (Income) Loss Attributable to Noncontrolling Interests	(13)	45	(1,417)
Net Income Attributable to Kinder Morgan, Inc.	708	253	1,026
Preferred Stock Dividends	(156)	(26)	—
Net Income Available to Common Stockholders	$552	$227	$1,026
Class P Shares			
Basic Earnings Per Common Share	$0.25	$0.10	$0.89
Basic Weighted Average Common Shares Outstanding	2,230	2,187	1,137

Diluted Earnings Per Common Share	$0.25	$0.10	$0.89
Diluted Weighted Average Common Shares Outstanding	2,230	2,193	1,137
Dividends Per Common Share Declared for the Period	$0.50	$1.605	$1.74

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In Millions)

	Year Ended December 31,		
	2016	2015	2014
Net income	$ 721	$ 208	$ 2,443
Other comprehensive income (loss), net of tax			
Change in fair value of hedge derivatives (net of tax benefit (expense) of $60, $(94) and $(163), respectively)	(104)	164	409
Reclassification of change in fair value of derivatives to net income (net of tax benefit of $67, $156 and $13, respectively)	(116)	(272)	(25)
Foreign currency translation adjustments (net of tax (expense) benefit of $(20), $123 and $48, respectively)	34	(214)	(138)
Benefit plan adjustments (net of tax benefit of $19, $69 and $126, respectively)	(14)	(122)	(226)
Total other comprehensive (loss) income	(200)	(444)	20
Comprehensive income (loss)	521	(236)	2,463
Comprehensive (income) loss attributable to noncontrolling interests	(13)	45	(1,486)
Comprehensive income (loss) attributable to KMI	$ 508	$ (191)	$ 977

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In Millions, Except Share and Per Share Amounts)

	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$684	$229
Restricted deposits	103	60
Accounts receivable, net	1,370	1,315
Fair value of derivative contracts	198	507
Inventories	357	407
Income tax receivable	180	40
Other current assets	337	266
Total current assets	3,229	2,824
Property, plant and equipment, net	38,705	40,547
Investments	7,027	6,040
Goodwill	22,152	23,790
Other intangibles, net	3,318	3,551
Deferred income taxes	4,352	5,323
Deferred charges and other assets	1,522	2,029
Total Assets	$80,305	$84,104
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of debt	$2,696	$821
Accounts payable	1,257	1,192
Accrued interest	625	695
Accrued contingencies	261	298
Other current liabilities	1,085	1,059
Total current liabilities	5,924	4,065
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	36,105	40,632
Preferred interest in general partner of KMP	100	100
Debt fair value adjustments	1,149	1,674
Total long-term debt	37,354	42,406
Other long-term liabilities and deferred credits	2,225	2,230
Total long-term liabilities and deferred credits	39,579	44,636
Total Liabilities	45,503	48,701
Commitments and contingencies (Notes 9, 13 and 17)		
Stockholders' Equity		
Class P shares, $0.01 par value, 4,000,000,000 shares authorized, 2,230,102,384 and 2,229,223,864 shares, respectively, issued and outstanding	22	22
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 9.75% Series A Mandatory Convertible, $1,000 per share liquidation preference, 1,600,000 shares issued and outstanding	—	—
Additional paid-in capital	41,739	41,661

Retained deficit	(6,669)	(6,103)
Accumulated other comprehensive loss	(661)	(461)
Total Kinder Morgan, Inc.'s stockholders' equity	34,431	35,119
Noncontrolling interests	371	284
Total Stockholders' Equity	34,802	35,403
Total Liabilities and Stockholders' Equity	$80,305	$84,104

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Millions)

	Year Ended December 31,		
	2016	2015	2014
Cash Flows From Operating Activities			
Net income	$ 721	$ 208	$ 2,443
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	2,209	2,309	2,040
Deferred income taxes	1,087	692	615
Amortization of excess cost of equity investments	59	51	45
Gain on early extinguishment of debt	(45)	—	—
Loss on impairment of goodwill (Note 4)	—	1,150	—
Loss on impairments and divestitures, net (Note 4)	387	919	274
Loss on impairments and divestitures of equity investments, net (Note 4)	610	30	—
Earnings from equity investments	(497)	(414)	(406)
Distributions of equity investment earnings	431	391	381
Pension contributions and noncash pension benefit credits	—	(85)	(88)
Changes in components of working capital, net of the effects of acquisitions			
Accounts receivable	(107)	382	(84)
Income tax receivable	(148)	195	(195)
Inventories	49	34	(30)
Other current assets	(81)	113	(17)
Accounts payable	144	(156)	(1)
Accrued interest, net of interest rate swaps	(18)	37	61
Accrued contingencies and other current liabilities	71	(129)	108
Rate reparations, refunds and other litigation reserve adjustments	(32)	18	(280)
Other, net	(53)	(442)	(399)
Net Cash Provided by Operating Activities	4,787	5,303	4,467
Cash Flows From Investing Activities			
Acquisitions of assets and investments, net of cash acquired	(333)	(2,079)	(1,388)
Capital expenditures	(2,882)	(3,896)	(3,617)
Proceeds from sale of equity interests in subsidiaries, net	1,401	—	—
Sales of property, plant and equipment, investments, and other net assets, net of removal costs	330	39	5
Contributions to investments	(408)	(96)	(389)
Distributions from equity investments in excess of cumulative earnings	231	228	182
Other, net	(44)	98	(3)
Net Cash Used in Investing Activities	(1,705)	(5,706)	(5,210)
Cash Flows From Financing Activities			
Issuances of debt	8,629	14,316	24,573
Payments of debt	(10,060)	(15,116)	(17,801)
Debt issue costs	(19)	(24)	(89)
Issuances of common shares (Note 11)	—	3,870	—
Issuance of mandatory convertible preferred stock (Note 11)	—	1,541	—
Cash dividends - common shares (Note 11)	(1,118)	(4,224)	(1,760)
Cash dividends - preferred shares (Note 11)	(154)	—	—
Repurchases of shares and warrants	—	(12)	(192)

Cash consideration of Merger Transactions (Note 1)	—	—	(3,937)
Merger Transactions costs	—	(2)	(74)
Contributions from noncontrolling interests	117	11	1,767
Distributions to noncontrolling interests	(24)	(34)	(2,013)
Other, net	—	1	(3)
Net Cash (Used in) Provided by Financing Activities	(2,629)	327	471
Effect of Exchange Rate Changes on Cash and Cash Equivalents	2	(10)	(11)
Net increase (decrease) in Cash and Cash Equivalents	455	(86)	(283)
Cash and Cash Equivalents, beginning of period	229	315	598
Cash and Cash Equivalents, end of period	$ 684	$ 229	$ 315

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
(In Millions)

	Year Ended December 31,		
	2016	2015	2014
Noncash Investing and Financing Activities			
Assets acquired by the assumption or incurrence of liabilities	$ 43	$ 1,681	$ 106
Net assets contributed to equity investments	37	46	—
Net assets and liabilities or noncontrolling interests acquired by the issuance of shares and warrants (Notes 1)	—	—	16,023
Supplemental Disclosures of Cash Flow Information			
Cash paid during the period for interest (net of capitalized interest)	2,050	1,985	1,718
Cash paid (refunded) during the period for income taxes, net	4	(331)	227

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In Millions)

	Common stock		Preferred stock							
	Issued shares	Par value	Issued shares	Par value	Additional paid-in capital	Retained deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
Balance at December 31, 2013	1,031	$ 10	—	$ —	$ 14,479	$ (1,372)	$ (24)	$ 13,093	$ 15,192	$ 28,285
Impact of Merger Transactions	1,097	11			21,880			21,891	(15,936)	5,955
Merger Transactions costs					(75)			(75)		(75)
Repurchase of shares and warrants	(3)				(192)			(192)		(192)
Restricted shares					52			52		52
Impact from equity transactions of KMP, EPB and KMR					36			36	(55)	(19)
Net income						1,026		1,026	1,417	2,443
Distributions								—	(2,013)	(2,013)
Contributions								—	1,767	1,767
Common stock dividends						(1,760)		(1,760)		(1,760)
Other					(2)			(2)	(4)	(6)
Other comprehensive (loss) income							(49)	(49)	69	20
Impact of Merger Transactions on Accumulated other comprehensive loss							56	56	(87)	(31)
Balance at December 31, 2014	2,125	21	—	—	36,178	(2,106)	(17)	34,076	350	34,426
Issuances of common shares	103	1			3,869			3,870		3,870
Issuances of preferred shares			2		1,541			1,541		1,541
Repurchase of warrants					(12)			(12)		(12)
EP Trust I Preferred security conversions	1				23			23		23
Warrants exercised					2			2		2
Restricted shares					57			57		57
Net income						253		253	(45)	208
Distributions								—	(34)	(34)
Contributions								—	11	11
Preferred stock dividends						(26)		(26)		(26)
Common stock dividends						(4,224)		(4,224)		(4,224)
Other					3			3	2	5
Other comprehensive loss							(444)	(444)		(444)
Balance at December 31, 2015	2,229	22	2	—	41,661	(6,103)	(461)	35,119	284	35,403
Restricted shares	1				66			66		66
Net income						708		708	13	721
Distributions								—	(24)	(24)
Contributions								—	117	117
Preferred stock dividends						(156)		(156)		(156)
Common stock dividends						(1,118)		(1,118)		(1,118)
Other					12			12	(19)	(7)

Other comprehensive loss							(200)	(200)		(200)
Balance at December 31, 2016	2,230	$ 22	2	$ —	$ 41,739	$ (6,669)	$ (661)	$ 34,431	$ 371	$ 34,802

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General

We are one of the largest energy infrastructure companies in North America and unless the context requires otherwise, references to "we," "us," "our," "the Company," or "KMI" are intended to mean Kinder Morgan, Inc. and its consolidated subsidiaries. Our pipelines transport natural gas, refined petroleum products, crude oil, condensate, CO_2 and other products, and our terminals transload and store petroleum products, ethanol and chemicals, and handle such products as steel, coal and petroleum coke. We are also a leading producer of CO_2, which we and others utilize for enhanced oil recovery projects primarily in the Permian basin.

On November 26, 2014, we completed our acquisition, pursuant to three separate merger agreements, of all of the outstanding common units of KMP and EPB and all of the outstanding shares of KMR that we did not already own. The transactions are referred to collectively as the "Merger Transactions."

As we controlled each of KMP, KMR and EPB and continued to control each of them after the Merger Transactions, the changes in our ownership interest in each of KMP, KMR and EPB were accounted for as an equity transaction and no gain or loss was recognized in our consolidated statements of income related to the Merger Transactions. After closing the Merger Transactions, KMR was merged with and into KMI. On January 1, 2015, EPB and its subsidiary, EPPOC, merged with and into KMP. References to EPB refer to EPB for periods prior to its merger into KMP.

Prior to the Merger Transactions, we owned an approximate 10% limited partner interest (including our interest in KMR) and the 2% general partner interest including incentive distribution rights in KMP, and an approximate 39% limited partner interest and the 2% general partner interest and incentive distribution rights in EPB. Effective with the Merger Transactions, the incentive distribution rights held by the general partner of KMP were eliminated.

The equity interests in KMP, EPB and KMR (which are all consolidated in our financial statements) owned by the public prior to the Merger Transactions are reflected within "Noncontrolling interests" in our accompanying consolidated statements of stockholders' equity. The earnings recorded by KMP, EPB and KMR that are attributed to their units and shares, respectively, held by the public prior to the Merger Transactions are reported as "Net (income) loss attributable to noncontrolling interests" in our accompanying consolidated statement of income for the year ended December 31, 2014.

Our common stock trades on the NYSE under the symbol "KMI."

2. Summary of Significant Accounting Policies

Basis of Presentation

Our reporting currency is U.S. dollars, and all references to dollars are U.S. dollars, unless stated otherwise. Our accompanying consolidated financial statements have been prepared under the rules and regulations of the SEC. These rules and regulations conform to the accounting principles contained in the FASB's Accounting Standards Codification, the single source of GAAP. Under such rules and regulations, all significant intercompany items have been eliminated in consolidation. Additionally, certain amounts from prior years have been reclassified to conform to the current presentation.

Use of Estimates

Certain amounts included in or affecting our financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities, our revenues and expenses during the reporting period, and our disclosures, including as it relates to contingent assets and liabilities at the date of our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Certain accounting policies are of more significance in our financial statement preparation process than others, and set out below are the principal accounting policies we apply in the preparation of our consolidated financial statements.

Cash Equivalents and Restricted Deposits

We define cash equivalents as all highly liquid short-term investments with original maturities of three months or less.

Restricted deposits were $103 million and $60 million as of December 31, 2016 and 2015, respectively.

Accounts Receivable, net

The amounts reported as "Accounts receivable, net" on our accompanying consolidated balance sheets as of December 31, 2016 and 2015 primarily consist of amounts due from customers net of the allowance for doubtful accounts.

Our policy for determining an appropriate allowance for doubtful accounts varies according to the type of business being conducted and the customers being served. Generally, we make periodic reviews and evaluations of the appropriateness of the allowance for doubtful accounts based on a historical analysis of uncollected amounts, and we record adjustments as necessary for changed circumstances and customer-specific information. When specific receivables are determined to be uncollectible, the reserve and receivable are relieved.

The allowance for doubtful accounts was $39 million and $91 million as of December 31, 2016 and 2015, respectively. The decrease was primarily associated with certain coal customers' receivables that were written off in 2016 and had been reserved in prior periods.

Inventories

Our inventories consist of materials and supplies and products such as, NGL, crude oil, condensate, refined petroleum products, transmix and natural gas. We report products inventory at the lower of weighted-average cost or net realizable value. We report materials and supplies inventories at cost, and periodically review for physical deterioration and obsolescence.

Gas Imbalances

We value gas imbalances due to or due from interconnecting pipelines at market prices. As of December 31, 2016 and 2015, our gas imbalance receivables—including both trade and related party receivables—totaled $108 million and $21 million, respectively, and we included these amounts within "Other current assets" on our accompanying consolidated balance sheets. As of December 31, 2016 and 2015, our gas imbalance payables—including both trade and related party payables—totaled $45 million and $17 million, respectively, and we included these amounts within "Other current liabilities" on our accompanying consolidated balance sheets.

Property, Plant and Equipment, net

Capitalization, Depreciation and Depletion and Disposals

We report property, plant and equipment at its acquisition cost. We expense costs for routine maintenance and repairs in the period incurred.

We generally compute depreciation using either the straight-line method based on estimated economic lives or, for certain depreciable assets, we employ the composite depreciation method, applying a single depreciation rate for a group of assets. Generally, we apply composite depreciation rates to functional groups of property having similar economic characteristics. The rates range from 1.09% to 23.0% excluding certain short-lived assets such as vehicles. For FERC-regulated entities, the FERC-accepted composite depreciation rate is applied to the total cost of the composite group until the net book value equals the salvage value. For other entities, depreciation estimates are based on various factors, including age (in the case of acquired assets), manufacturing specifications, technological advances, contract term for assets on leased or customer property and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives (and salvage values where appropriate) that we believe are reasonable. Subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization expense. Historically, adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year.

Our oil and gas producing activities are accounted for under the successful efforts method of accounting. Under this method costs that are incurred to acquire leasehold and subsequent development costs are capitalized. Costs that are associated with the drilling of successful exploration wells are capitalized if proved reserves are found. Costs associated with the drilling of exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of certain non-producing leasehold costs are expensed as incurred. The capitalized costs of our producing oil and gas properties are depreciated and depleted by the units-of-production method. Other miscellaneous property, plant and equipment are depreciated over the estimated useful lives of the asset.

We engage in enhanced recovery techniques in which CO_2 is injected into certain producing oil reservoirs. In some cases, the cost of the CO_2 associated with enhanced recovery is capitalized as part of our development costs when it is injected. The cost of CO_2 associated with pressure maintenance operations for reservoir management is expensed when it is injected. When CO_2 is recovered in conjunction with oil production, it is extracted and re-injected, and all of the associated costs are expensed as incurred. Proved developed reserves are used in computing units of production rates for drilling and development costs, and total proved reserves are used for depletion of leasehold costs. The units-of-production depreciation rate is determined by field and for our oil and gas producing fields that have no proved reserves, the units-of-production depreciation rate is based on each field’s probable reserves and NYMEX forward curve prices.

A gain on the sale of property, plant and equipment used in our oil and gas producing activities or in our bulk and liquids terminal activities is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sales proceeds received. A gain on an asset disposal is recognized in income in the period that the sale is closed. A loss on the sale of property, plant and equipment is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sales proceeds received or the market value if the asset is being held for sale. A loss is recognized when the asset is sold or when the net cost of an asset held for sale is greater than the market value of the asset. For our pipeline system assets under the composite method of depreciation, we generally charge the original cost of property sold or retired to accumulated depreciation and amortization, net of salvage and cost of removal. Gains and losses are booked for operating unit sales and land sales and are recorded to income or expense accounts in accordance with regulatory accounting guidelines. In those instances where we receive recovery in tariff rates related to losses on dispositions of operating units, we record a regulatory asset for the estimated recoverable amount.

Asset Retirement Obligations

We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. We record, as liabilities, the fair value of asset retirement obligations on a discounted basis when they are incurred and can be reasonably estimated, which is typically at the time the assets are installed or acquired. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the change in their present value, and the initial capitalized costs are depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service.

We have various other obligations throughout our businesses to remove facilities and equipment on rights-of-way and other leased facilities. We currently cannot reasonably estimate the fair value of these obligations because the associated assets have indeterminate lives. These assets include pipelines, certain processing plants and distribution facilities, and certain bulk and liquids terminal facilities. An asset retirement obligation, if any, will be recognized once sufficient information is available to reasonably estimate the fair value of the obligation.

Long-lived Asset Impairments

We evaluate long-lived assets and investments for impairment whenever events or changes in circumstances indicate that our carrying amount of an asset or investment may not be recoverable. We recognize impairment losses when estimated future cash flows expected to result from our use of the asset and its eventual disposition is less than its carrying amount.

Prior to us conducting the goodwill impairment test, to the extent triggering events exist, we complete a review of the carrying value of our long-lived assets, including property, plant and equipment as well as other intangibles, and record, as applicable, the appropriate impairments. Because the impairment test for long-lived assets held in use is based on undiscounted cash flows, there may be instances where an asset or asset group is not considered impaired, even when its fair value may be less than its carrying value, because the asset or asset group is recoverable based on the cash flows to be generated over the estimated life of the asset or asset group.

We evaluate our oil and gas producing properties for impairment of value on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure, using undiscounted future cash flows based on total proved and risk-adjusted probable reserves.

Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future cash flows based on total proved and risk-adjusted probable and possible reserves or, if available, comparable market values. Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment.

Equity Method of Accounting and Excess Investment Cost

We account for investments which we do not control, but do have the ability to exercise significant influence using the equity method of accounting. Under this method, our equity investments are carried originally at our acquisition cost, increased by our proportionate share of the investee’s net income and by contributions made, and decreased by our proportionate share of the investee’s net losses and by distributions received.

With regard to our equity investments in unconsolidated affiliates, in almost all cases, either (i) the price we paid to acquire our share of the net assets of such equity investees or (ii) the revaluation of our share of the net assets of any retained noncontrolling equity investment (from the sale of a portion of our ownership interest in a consolidated subsidiary, thereby losing our controlling financial interest in the subsidiary) differed from the underlying carrying value of such net assets. This differential consists of two pieces. First, an amount related to the difference between the investee’s recognized net assets at book value and at current fair values (representing the appreciated value in plant and other net assets), and secondly, to any premium in excess of fair value (referred to as equity method goodwill) we paid to acquire the investment. We include both amounts within “Investments” on our accompanying consolidated balance sheets.

The first differential, representing the excess of the fair market value of our investees’ plant and other net assets over its underlying book value at either the date of acquisition or the date of the loss of control totaled $767 million and $808 million as of December 31, 2016 and 2015, respectively. Generally, this basis difference relates to our share of the underlying depreciable assets, and, as such, we amortize this portion of our investment cost against our share of investee earnings. As of December 31, 2016, this excess investment cost is being amortized over a weighted average life of approximately fourteen years.

The second differential, representing equity method goodwill, totaled $956 million and $138 million, as of December 31, 2016 and 2015, respectively. This differential is not subject to amortization but rather to impairment testing as part of our periodic evaluation of the recoverability of our investment as compared to the fair value of net assets accounted for under the equity method. Our impairment test considers whether the fair value of the equity investment as a whole has declined and whether that decline is other than temporary. The increase in the equity method goodwill balance from December 31, 2015 is due to the sale of a 50% interest in our SNG natural gas pipeline system, see Note 3.

Goodwill

Goodwill is the cost of an acquisition in excess of the fair value of acquired assets and liabilities and is recorded as an asset on our balance sheet. Goodwill is not subject to amortization but must be tested for impairment at least annually. This test requires us to assign goodwill to an appropriate reporting unit and to determine if the implied fair value of the reporting unit’s goodwill is less than its carrying amount.

We evaluate goodwill for impairment on May 31 of each year. For this purpose, we have seven reporting units as follows: (i) Products Pipelines (excluding associated terminals); (ii) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes); (iii) Natural Gas Pipelines Regulated; (iv) Natural Gas Pipelines Non-Regulated; (v) CO_2; (vi) Terminals; and (vii) Kinder Morgan Canada. We also evaluate goodwill for impairment to the extent events or conditions indicate a risk of possible impairment during the interim periods subsequent to our annual impairment test. Generally, the evaluation of goodwill for impairment involves a two-step test, although under certain circumstance an initial qualitative evaluation may be sufficient to conclude that goodwill is not impaired without conducting the quantitative test.

Step 1 involves comparing the estimated fair value of each respective reporting unit to its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, the reporting unit’s goodwill is not considered impaired. If the carrying value exceeds the estimated fair value, step 2 must be performed to determine whether goodwill is impaired and, if so, the amount of the impairment. Step 2 involves calculating an implied fair value of goodwill by performing a hypothetical allocation of the estimated fair value of the reporting unit determined in step 1 to the respective tangible and intangible net assets of the reporting unit. The remaining implied goodwill is then compared to the actual carrying amount of the goodwill for the reporting unit. To the extent the carrying amount of goodwill exceeds the implied goodwill, the difference is the amount of the goodwill impairment.

A large portion of our goodwill is non-deductible for tax purposes, and as such, to the extent there are impairments, all or a portion of the impairment may not result in a corresponding tax benefit.

Refer to Note 8 for further information.

Other Intangibles

Excluding goodwill, our other intangible assets include customer contracts, relationships and agreements, lease value, and technology-based assets. As of December 31, 2016 and 2015, the gross carrying amounts of these intangible assets was $4,305 million and $4,335 million, respectively and the accumulated amortization was $986 million and $784 million, respectively, resulting in net carrying amounts of $3,318 million and $3,551 million, respectively. These intangible assets primarily consisted of customer contracts, relationships and agreements associated with our Natural Gas Pipelines and Terminals business segments.

Primarily, these contracts, relationships and agreements relate to the gathering of natural gas, and the handling and storage of petroleum, chemical, and dry-bulk materials, including oil, gasoline and other refined petroleum products, petroleum coke, steel and ores. We determined the values of these intangible assets by first, estimating the revenues derived from a customer contract or relationship (offset by the cost and expenses of supporting assets to fulfill the contract), and second, discounting the revenues at a risk adjusted discount rate.

We amortize the costs of our intangible assets to expense in a systematic and rational manner over their estimated useful lives. The life of each intangible asset is based either on the life of the corresponding customer contract or agreement or, in the case of a customer relationship intangible (the life of which was determined by an analysis of all available data on that business relationship), the length of time used in the discounted cash flow analysis to determine the value of the customer relationship. Among the factors we weigh, depending on the nature of the asset, are the effect of obsolescence, new technology, and competition.

For the years ended December 31, 2016, 2015 and 2014, the amortization expense on our intangibles totaled $223 million, $221 million and $143 million, respectively. Our estimated amortization expense for our intangible assets for each of the next five fiscal years (2017 – 2021) is approximately $215 million, $213 million, $211 million, $209 million, and $208 million, respectively. As of December 31, 2016, the weighted average amortization period for our intangible assets was approximately seventeen years.

Other intangibles are evaluated for recoverability consistent with the discussion above on long-lived asset impairments.

Revenue Recognition

We recognize revenue as services are rendered or goods are delivered and, if applicable, risk of loss has passed. We recognize natural gas, crude and NGL sales revenue when the commodity is sold to a purchaser at a fixed or determinable price, delivery has occurred and risk of loss has transferred, and collectability of the revenue is reasonably assured. Our sales and purchases of natural gas, crude and NGL are primarily accounted for on a gross basis as natural gas sales or product sales, as applicable, and cost of sales, except in circumstances where we solely act as an agent and do not have price and related risk of ownership, in which case we recognize revenue on a net basis.

In addition to storing and transporting a significant portion of the natural gas volumes we purchase and resell, we provide various types of natural gas storage and transportation services for third-party customers. Under these contracts, the natural gas remains the property of these customers at all times. In many cases, generally described as firm service, the customer pays a two-part rate that includes (i) a fixed fee reserving the right to transport or store natural gas in our facilities and (ii) a per-unit rate for volumes actually transported or injected into/withdrawn from storage. The fixed-fee component of the overall rate is recognized as revenue in the period the service is provided. The per-unit charge is recognized as revenue when the volumes are delivered to the customers' agreed upon delivery point, or when the volumes are injected into/withdrawn from our storage facilities.

In other cases, generally described as interruptible service, there is no fixed fee associated with the services because the customer accepts the possibility that service may be interrupted at our discretion in order to serve customers who have purchased firm service. In the case of interruptible service, revenue is recognized in the same manner utilized for the per-unit rate for volumes actually transported under firm service agreements.

We provide crude oil and refined petroleum products transportation and storage services to customers. Revenues are recorded when products are delivered and services have been provided, and adjusted according to terms prescribed by the toll settlements with shippers and approved by regulatory authorities.

We recognize bulk terminal transfer service revenues based on volumes loaded and unloaded. We recognize liquids terminal tank rental revenue ratably over the contract period. We recognize liquids terminal throughput revenue based on volumes received and volumes delivered. We recognize transmix processing revenues based on volumes processed or sold, and if applicable, when risk of loss has passed. We recognize energy-related product sales revenues based on delivered quantities of product.

Revenues from the sale of crude oil, NGL, CO_2 and natural gas production within the CO_2 business segment are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on our net interest. We record our entitled share of revenues based on entitled volumes and contracted sales prices. Since there is a ready market for oil and gas production, we sell the majority of our products soon after production at various locations, at which time title and risk of loss pass to the buyer.

Cost of Sales

Cost of sales primarily includes the cost of energy commodities sold, including natural gas, NGL and other refined petroleum products, adjusted for the effects of our energy commodity activities, as applicable, other than production from our CO_2 business segment.

Operations and Maintenance

Operations and maintenance include costs of services and is primarily comprised of (i) operational labor costs and (ii) operations, maintenance and asset integrity, regulatory and environmental costs. Costs associated with our oil, gas and carbon dioxide producing activities included within operations and maintenance totaled $349 million, $366 million and $403 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Environmental Matters

We capitalize or expense, as appropriate, environmental expenditures. We capitalize certain environmental expenditures required in obtaining rights-of-way, regulatory approvals or permitting as part of the construction. We accrue and expense environmental costs that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We generally do not discount environmental liabilities to a net present value, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable. We record at estimated fair value, where appropriate, environmental liabilities assumed in a business combination.

We routinely conduct reviews of potential environmental issues and claims that could impact our assets or operations. These reviews assist us in identifying environmental issues and estimating the costs and timing of remediation efforts. We also routinely adjust our environmental liabilities to reflect changes in previous estimates. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us, and potential third-party liability claims. Often, as the remediation evaluation and effort progresses, additional information is obtained, requiring revisions to estimated costs. These revisions are reflected in our income in the period in which they are reasonably determinable.

Pensions and Other Postretirement Benefits

We recognize the differences between the fair value of each of our and our consolidated subsidiaries' pension and other postretirement benefit plans' assets and the benefit obligations as either assets or liabilities on our consolidated balance sheet. We record deferred plan costs and income—unrecognized losses and gains, unrecognized prior service costs and credits, and any remaining unamortized transition obligations—in “Accumulated other comprehensive loss” or as a regulatory asset or liability for certain of our regulated operations, until they are amortized as a component of benefit expense.

Noncontrolling Interests

Noncontrolling interests represents the interests in our consolidated subsidiaries that are not owned by us. In our accompanying consolidated income statements, the noncontrolling interest in the net income (or loss) of our consolidated subsidiaries is shown as an allocation of our consolidated net income and is presented separately as “Net (Income) Loss Attributable to Noncontrolling Interests.” In our accompanying consolidated balance sheets, noncontrolling interests is presented separately as “Noncontrolling interests” within “Stockholders’ Equity.”

Income Taxes

Income tax expense is recorded based on an estimate of the effective tax rate in effect or to be in effect during the relevant periods. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. We do business in a number of states with differing laws concerning how income subject to each state’s tax structure is measured and at what effective rate such income is taxed. Therefore, we must make estimates of how our income will be apportioned among the various states in order to arrive at an overall effective tax rate. Changes in our effective rate, including any effect on previously recorded deferred taxes, are recorded in the period in which the need for such change is identified.

Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Deferred tax assets are reduced by a valuation allowance for the amount that is more likely than not to be realized. While we have considered estimated future taxable income and prudent and feasible tax planning strategies in determining the amount of our valuation allowance, any change in the amount that we expect to ultimately realize will be included in income in the period in which such a determination is reached.

In determining the deferred income tax asset and liability balances attributable to our investments, we apply an accounting policy that looks through our investments. The application of this policy resulted in no deferred income taxes being provided on the difference between the book and tax basis on the non-tax-deductible goodwill portion of our investments.

Foreign Currency Transactions and Translation

Foreign currency transaction gains or losses result from a change in exchange rates between (i) the functional currency, for example the Canadian dollar for a Canadian subsidiary and (ii) the currency in which a foreign currency transaction is denominated, for example the U.S. dollar for a Canadian subsidiary. In our accompanying consolidated statements of income, gains and losses from our foreign currency transactions are included within “Other Income (Expense)—Other, net.”

Foreign currency translation is the process of expressing, in U.S. dollars, amounts recorded in a local functional currency other than U.S. dollars, for example the Canadian dollar for a Canadian subsidiary. We translate the assets and liabilities of each of our consolidated foreign subsidiaries that have a local functional currency to U.S. dollars at year-end exchange rates. Income and expense items are translated at weighted-average rates of exchange prevailing during the year and stockholders’ equity accounts are translated by using historical exchange rates. The cumulative translation adjustments balance is reported as a component of “Accumulated other comprehensive loss.”

Risk Management Activities

We utilize energy commodity derivative contracts for the purpose of mitigating our risk resulting from fluctuations in the market price of commodities including natural gas, NGL and crude oil. In addition, we enter into interest rate swap agreements for the purpose of hedging the interest rate risk associated with our debt obligations. We also enter into cross-currency swap agreements to manage our foreign currency risk with certain debt obligations. We measure our derivative contracts at fair value and we report them on our balance sheet as either an asset or liability. For certain physical forward commodity derivatives contracts, we apply the normal purchase/normal sale exception, whereby the revenues and expenses associated with such transactions are recognized during the period when the commodities are physically delivered or received.

For qualifying accounting hedges, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives and the methods used for assessing and testing effectiveness, and how any ineffectiveness will be measured and recorded. If we designate a derivative contract as a cash flow accounting hedge, the effective portion of the change in fair value of the derivative is deferred in accumulated other comprehensive income/(loss) and reclassified into earnings in the period in which the hedged item affects earnings. Any ineffective portion of the derivative's change in fair value or amount excluded from the assessment of hedge effectiveness is recognized currently in earnings. If we designate a derivative contract as a fair value accounting hedge, the effective portion of the change in fair value of the derivative is recorded as an adjustment to the item being hedged. Any ineffective portion of the derivative's change in fair value is recognized currently in earnings.

For derivative instruments that are not designated as accounting hedges, or for which we have not elected the normal purchase/normal sales exception, changes in fair value are recognized currently in earnings.

Regulatory Assets and Liabilities

Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. We included the amounts of our regulatory assets and liabilities within "Other current assets," "Deferred charges and other assets," "Other current liabilities" and "Other long-term liabilities and deferred credits," respectively, in our accompanying consolidated balance sheets.

The following table summarizes our regulatory asset and liability balances as of December 31, 2016 and 2015 (in millions):

	December 31,	
	2016	2015
Current regulatory assets	$49	$55
Non-current regulatory assets	330	378
Total regulatory assets(a)	$379	$433
Current regulatory liabilities	$101	$161
Non-current regulatory liabilities	108	166
Total regulatory liabilities(b)	$209	$327

(a) Regulatory assets as of December 31, 2016 include (i) $188 million of unamortized losses on disposal of assets; (ii) $107 million income tax gross up on equity AFUDC; and (iii) $84 million of other assets including amounts related to fuel tracker arrangements. Approximately $172 million of the regulatory assets, with a weighted average remaining recovery period of 20 years, are recoverable without earning a return, including the income tax gross up on equity AFUDC for which there is an offsetting deferred income tax balance for FERC rate base purposes, and therefore, it does not earn a return.

(b) Regulatory liabilities as of December 31, 2016 are comprised of customer prepayments to be credited to shippers or other over-collections that are expected to be returned to shippers or netted against under-collections over time. Approximately $24 million of the $108 million classified as non-current is expected to be credited to shippers over a remaining weighted average period of 22 years, while the remaining $84 million is not subject to a defined period.

Transfer of Net Assets Between Entities Under Common Control

We account for the transfer of net assets between entities under common control by carrying forward the net assets recognized in the balance sheets of each combining entity to the balance sheet of the combined entity, and no other assets or liabilities are recognized as a result of the combination. Transfers of net assets between entities under common control do not affect the historical income statement or balance sheet of the combined entity.

Earnings per Share

We calculate earnings per share using the two-class method. Earnings were allocated to Class P shares of common stock and participating securities based on the amount of dividends paid in the current period plus an allocation of the undistributed earnings or excess distributions over earnings to the extent that each security participates in earnings or excess distributions over earnings. Our unvested restricted stock awards, which may be stock or stock units issued to management employees and include dividend equivalent payments, do not participate in excess distributions over earnings.

The following tables set forth the allocation of net income available to shareholders of Class P shares and participating securities and the reconciliation of Basic Weighted Average Common Shares Outstanding to Diluted Weighted Average Common Shares Outstanding (in millions):

	Year Ended December 31,		
	2016	2015	2014
Class P	$548	$214	$1,015
Participating securities:			
Restricted stock awards(a)	4	13	11
Net Income Available to Common Stockholders	$552	$227	$1,026

	Year Ended December 31,		
	2016	2015	2014
Basic Weighted Average Common Shares Outstanding	2,230	2,187	1,137
Effect of dilutive securities:			
Warrants	—	6	—
Diluted Weighted Average Common Shares Outstanding	2,230	2,193	1,137

(a) As of December 31, 2016, there were approximately 9 million such restricted stock awards.

The following maximum number of potential common stock equivalents are antidilutive and, accordingly, are excluded from the determination of diluted earnings per share (in millions on a weighted average basis):

	Year Ended December 31,		
	2016	2015	2014
Unvested restricted stock awards	8	7	7
Warrants to purchase our Class P shares(a)	293	291	312
Convertible trust preferred securities	8	8	10
Mandatory convertible preferred stock(b)	58	10	n/a

n/a - not applicable

(a) Each warrant entitles the holder to purchase one share of our common stock for an exercise price of $40 per share, payable in cash or by cashless exercise, at any time until May 25, 2017. The potential dilutive effect of the warrants does not consider the assumed proceeds to KMI upon exercise.

(b) Until our mandatory convertible preferred shares are converted to common shares, on or before the expected mandatory conversion date of October 26, 2018, the holder of each preferred share participates in our earnings by receiving preferred dividends.

3. Acquisitions and Divestitures

Business Combinations

During 2016, 2015 and 2014, we completed the following significant acquisitions.

Allocation of Purchase Price

As of December 31, 2016, the evaluation of the assigned fair values for the BP terminals acquisition was ongoing and subject to adjustment. As of December 31, 2016, our preliminary allocation of the purchase price for the BP terminals acquisition and the purchase allocation for other significant acquisitions completed during 2016, 2015 and 2014 are detailed below (in millions):

				Assignment of Purchase Price					
Ref.	Date	Acquisition	Purchase price	Current assets	Property plant & equipment	Deferred charges & other	Goodwill	Debt	Other liabilities
(1)	2/16	BP Products North America Inc. Terminal Assets	$ 349	$ 2	$ 396	$ —	$ —	$ —	$ (49)
(2)	2/15	Vopak Terminal Assets	158	2	155	—	6	—	(5)
(3)	2/15	Hiland	1,709	79	1,492	1,498	310	(1,413)	(257)
(4)	11/14	Pennsylvania and Florida Jones Act Tankers	270	—	270	8	25	—	(33)
(5)	1/14	American Petroleum Tankers and State Class Tankers	961	6	951	6	64	—	(66)

After measuring all of the identifiable tangible and intangible assets acquired and liabilities assumed at fair value on the acquisition date, goodwill is an intangible asset representing the future economic benefits expected to be derived from an acquisition that are not assigned to other identifiable, separately recognizable assets. We believe the primary items that generated our goodwill are both the value of the synergies created between the acquired assets and our pre-existing assets, and our expected ability to grow the business we acquired by leveraging our pre-existing business experience. We apply a look through method of recording deferred income taxes on the outside book-tax basis differences in our investments. As a result, no deferred income taxes are recorded associated with non-deductible goodwill recorded at the investee level.

(1) BP Products North America Inc. (BP) Terminal Assets

On February 1, 2016, we completed the acquisition of 15 products terminals and associated infrastructure from BP for $349 million, including a transaction deposit paid in 2015 and working capital adjustments paid in 2016. In conjunction with this transaction, we and BP formed a joint venture with an equity ownership interest of 75% and 25%, respectively. Subsequent to the acquisition, we contributed 14 of the acquired terminals to the joint venture, which we operate, and the remaining terminal is solely owned by us. BP acquired its 25% interest in the joint venture for $84 million, which we reported as “Contributions from noncontrolling interests” within our accompanying consolidated statement of cash flows for the year ended December 31, 2016. Of the acquired assets, 10 terminals are included in our Terminals business segment and 5 terminals are included in our Products Pipelines business segment based on synergies with each segment’s respective existing operations.

(2) Vopak Terminal Assets

On February 27, 2015, we acquired three U.S. terminals and one undeveloped site from Royal Vopak (Vopak) for approximately $158 million in cash. The acquisition included (i) a 36-acre, 1,069,500-barrel storage facility at Galena Park, Texas that handles base oils, biodiesel and crude oil and is immediately adjacent to our Galena Park terminal facility; (ii) two terminals in North Carolina: one in North Wilmington that handles chemicals and black oil and the other in South Wilmington that is not currently operating; and (iii) an undeveloped waterfront access site in Perth Amboy, New Jersey. We include the acquired assets as part of our Terminals business segment.

(3) Hiland

On February 13, 2015, we acquired Hiland, a privately held Delaware limited partnership for aggregate consideration of approximately $3,122 million, including assumed debt. Approximately $368 million of the debt assumed was immediately paid down after closing. Hiland's assets consist primarily of crude oil gathering and transportation pipelines and gas gathering and processing systems, primarily handling production from the Bakken Formation in North Dakota and Montana. The acquired gathering and processing assets are included in our Natural Gas Pipelines business segment while the acquired crude oil transport pipeline (Double H pipeline) is included in our Products Pipelines business segment. Deferred charges and other relates to customer contracts and relationships with a weighted average amortization period as of the acquisition date of 16.4 years.

(4) Pennsylvania and Florida Jones Act Tankers

On November 5, 2014, we acquired two Jones Act tankers from Crowley Maritime Corporation (Crowley) for approximately $270 million. The MT Pennsylvania and the MT Florida engage in the marine transportation of crude oil, condensate and refined products in the U.S. domestic trade, commonly referred to as the Jones Act trade, and are currently operating pursuant to multi-year charters with a major integrated oil company. The vessels each have approximately 330 MBbl of cargo capacity and are included in our Terminals business segment.

(5) American Petroleum Tankers and State Class Tankers

Effective January 17, 2014, we acquired APT and State Class Tankers (SCT) for aggregate consideration of $961 million in cash (the APT acquisition). APT is engaged in Jones Act trade and its primary assets consist of a fleet of five medium range Jones Act qualified product tankers, each with 330 MBbl of cargo capacity, and each operating pursuant to long-term time charters with high quality counterparties, including major integrated oil companies, major refiners and the U.S. Military Sealift Command. As of the closing date, the vessels' time charters had an average remaining term of approximately four years, with renewal options to extend the terms by an average of two years.

SCT commissioned the construction of four medium range Jones Act qualified product tankers, by General Dynamics' NASSCO shipyard, each with 330 MBbl of cargo capacity and were delivered in 2015 and 2016. The time charters for each vessel upon completion had an initial term of five years, with renewal options to extend the term by up to three years. The APT acquisition complements and extends our existing crude oil and refined products transportation and storage business. We include the acquired assets as part of our Terminals business segment.

Asset Purchase

On July 15, 2015, we purchased from Shell US Gas & Power LLC (Shell) its 49% interest in a joint venture, ELC, that was in the pre-construction stage of development for liquefaction facilities at Elba Island, Georgia. The transaction was treated as an asset purchase for the net cash consideration of $185 million. The purchase gives us full ownership and control of ELC. Therefore, we prospectively changed our method of accounting for ELC from the equity method to full consolidation. Shell remains subscribed to 100% of the liquefaction capacity.

Investment Acquisition

On December 10, 2015, we and Brookfield Infrastructure Partners L.P. (Brookfield) acquired from Myria Holdings, Inc. the 53% equity interest in NGPL Holdings LLC not previously owned by us and Brookfield, increasing our ownership to 50% with Brookfield owning the remaining 50%. We paid $136 million for our additional 30% interest in NGPL Holdings LLC. See Note 7 for additional information regarding our equity interests in NGPL Holdings LLC.

Sale of Equity Interest and Terminal Assets

Sale of Equity Interest in SNG

On September 1, 2016, we completed the sale of a 50% interest in our SNG natural gas pipeline system to The Southern Company (Southern Company), receiving proceeds of $1.4 billion, and the formation of a joint venture, which includes our remaining 50% interest in SNG. We used the proceeds from the sale to reduce outstanding debt (see Note 9). We recognized a pre-tax loss of $84 million on the sale of our interest in SNG which is included within “Loss on impairments and divestitures, net” on the accompanying consolidated statement of income for the year ended December 31, 2016. As a result of this transaction, we no longer hold a controlling interest in SNG or Bear Creek Storage Company, LLC (Bear Creek) (50% of which is owned by SNG) and, as such, we now account for our remaining equity interests in SNG and Bear Creek as equity investments.

Terminals Asset Sale

In October 2016, we entered into a definitive agreement to sell 20 bulk terminals to an affiliate of Watco Companies, LLC for approximately $100 million. The terminals are predominantly located along the inland river system and handle mostly coal and steel products, and are included within our Terminals business segment. The sale of seven of the locations closed in the fourth quarter of 2016, for which we received $37 million of the total consideration, with the balance of this transaction expected to close by April 2017 as certain conditions are satisfied. As a result of this transaction, we recognized a pre-tax loss of $81 million, including a $7 million reduction of goodwill, which is included within “Loss on impairments and divestitures, net” on our accompanying December 31, 2016 consolidated statement of income for the year ended December 31, 2016, and we have classified $61 million as held for sale for the remaining thirteen locations which is included within “Other current assets” on our accompanying consolidated balance sheet at December 31, 2016.

4. Impairments and Losses on Divestitures

During the years ended December 31, 2016, 2015, and 2014, we recorded impairments of certain equity investments, long-lived assets, and intangible assets, and net losses on divestitures totaling $1,013 million, $2,125 million, and $274 million, respectively. These adjustments were precipitated by a period of sustained deterioration in commodity prices which impacted the values of certain of our assets because of lower customer demand and, in the case of our CO_2 segment, reduced economics on our oil and gas properties. This lower commodity price environment led us to cancel certain projects that were in progress and divest of certain assets. For two of our equity investments in the Natural Gas Pipelines business segment, we determined that the negative outlook for long-term transportation contracts for those entities resulted in an other than temporary impairment of those investments in 2016 leading to a fair value write-down.

In addition, an interim goodwill impairment test was performed during the fourth quarter of 2015 resulting in a partial impairment of goodwill in our Natural Gas Pipelines Non-Regulated reporting unit of approximately $1,150 million. See Note 8 for further information.

These impairments require management to estimate fair value of these assets. The impairments resulting from decisions to classify assets as held-for-sale are based on the value expected to be realized in the transaction which is generally known at the time. The estimates of fair value are based on Level 3 valuation estimates using industry standard income approach valuation methodologies which include assumptions primarily involving management’s significant judgments and estimates with respect to general economic conditions and the related demand for products handled or transported by our assets as well as assumptions regarding commodity prices, future cash flows based on rate and volume assumptions, terminal values and discount rates. In certain cases, management’s decisions to dispose of certain assets may trigger an impairment. We typically use discounted cash flow analyses to determine the fair value of our assets. We may probability weight various forecasted cash flow scenarios utilized in the analysis as we consider the possible outcomes. We use discount rates representing our estimate of the risk-adjusted discount rates that would be used by market participants specific to the particular asset.

We may identify additional triggering events requiring future evaluations of the recoverability of the carrying value of our long-lived assets, investments and goodwill. Because certain of our assets, including certain equity investments and oil and gas producing properties, have been written down to fair value, any deterioration in fair value relative to our carrying value increases the likelihood of further impairments. Such non-cash impairments could have a significant effect on our results of operations, which would be recognized in the period in which the carrying value is determined to not be fully recoverable.

We recognized the following non-cash pre-tax impairment charges and losses (gains) on divestitures of assets (in millions):

	Year Ended December 31,		
	2016	2015	2014
Natural Gas Pipelines			
Impairment of goodwill	$—	$1,150	$—
Impairments of long-lived assets(a)	106	79	—
Losses on divestitures of long-lived assets(b)	94	43	5
Impairment of equity investments(c)	606	26	—
Impairment at equity investee(d)	7	—	—
CO_2			
Impairments of long-lived assets(e)	20	606	243
Gains on divestitures of long-lived assets	(1)	—	—
Impairment at equity investee(d)	9	26	—
Terminals			
Impairments of long-lived assets(f)	19	188	—
Losses on divestitures of long-lived assets(g)	80	3	29
Losses on impairments and divestitures of equity investments, net	16	4	—
Products Pipelines			
Impairments of long-lived assets(h)	66	—	—
Losses (gains) on divestitures of long-lived assets	10	1	(3)
Gain on divestiture of equity investment	(12)	—	—
Other gains on divestitures of long-lived assets	(7)	(1)	—
Pre-tax losses on impairments and divestitures, net	$1,013	$2,125	$274

(a) 2016 amount represents the project write-off of our portion of the Northeast Energy Direct (NED) Market project. 2015 amount represents $47 million and $32 million of project write-offs in our non-regulated midstream and regulated natural gas pipelines assets, respectively.
(b) 2016 amount primarily relates to our sale of a 50% interest in SNG.
(c) 2016 amount includes a $350 million impairment of our investment in MEP and a $250 million impairment of our investment in Ruby. 2015 amount is primarily related to an impairment of an investment in a gathering and processing asset in Oklahoma.
(d) 2016 and 2015 amounts are losses on impairments recorded by equity investees and included in “Earnings from equity investments” in our accompanying consolidated statements of income.
(e) 2015 amount includes (i) $399 million related to oil and gas properties and (ii) $207 million related to the certain CO_2 source and transportation project write-offs. 2014 amount is primarily related to oil and gas properties.
(f) 2015 amount is primarily related to certain terminals with significant coal operations, including a $175 million impairment of a terminal facility reflecting the impact of an agreement to adjust certain payment terms under a contract with a coal customer in February 2016.
(g) 2016 amount primarily relates to an agreement to sell 20 bulk terminals that handle mostly coal and steel products, predominately located along the inland river system. The sale of seven locations closed in the fourth quarter of 2016.
(h) 2016 amount represents project write-offs associated with the canceled Palmetto project.

5. Income Taxes

The components of “Income Before Income Taxes” are as follows (in millions):

	Year Ended December 31,		
	2016	2015	2014

U.S.	$ 1,466	$ 611	$ 2,941
Foreign	172	161	150
Total Income Before Income Taxes	$ 1,638	$ 772	$ 3,091

Components of the income tax provision applicable for federal, foreign and state taxes are as follows (in millions):

	Year Ended December 31,		
	2016	2015	2014
Current tax expense (benefit)			
Federal	$ (148)	$ (125)	$ (16)
State	(28)	(7)	36
Foreign	6	4	13
Total	(170)	(128)	33
Deferred tax expense (benefit)			
Federal	998	653	572
State	51	(4)	14
Foreign	38	43	29
Total	1,087	692	615
Total tax provision	$ 917	$ 564	$ 648

The difference between the statutory federal income tax rate and our effective income tax rate is summarized as follows (in millions, except percentages):

	Year Ended December 31,					
	2016		2015		2014	
Federal income tax	$573	35.0 %	$271	35.0 %	$1,082	35.0 %
Increase (decrease) as a result of:						
State deferred tax rate change	11	0.7 %	(24)	(3.1)%	—	— %
Taxes on foreign earnings	28	1.7 %	26	3.5 %	40	1.3 %
Net effects of consolidating KMP and EPB and other noncontrolling interests	(4)	(0.3)%	15	2.0 %	(433)	(14.0)%
State income tax, net of federal benefit	26	1.6 %	12	1.5 %	37	1.2 %
Dividend received deduction	(48)	(2.9)%	(51)	(6.6)%	(50)	(1.6)%
Adjustments to uncertain tax positions	(23)	(1.4)%	(14)	(1.9)%	(5)	(0.2)%
Valuation allowance on investment and tax credits	34	2.1 %	—	— %	61	2.0 %
Disposition of certain international holdings	—	— %	—	— %	(112)	(3.6)%
Nondeductible goodwill	301	18.5 %	323	41.7 %	—	— %
Other	19	1.1 %	6	0.8 %	28	0.9 %
Total	$917	56.1 %	$564	72.9 %	$648	21.0 %

Deferred tax assets and liabilities result from the following (in millions):

	December 31,	
	2016	2015
Deferred tax assets		
Employee benefits	$401	$394
Accrued expenses	118	129
Net operating loss, capital loss and tax credit carryforwards	1,307	1,344
Derivative instruments and interest rate and currency swaps	22	45
Debt fair value adjustment	74	110
Investments	2,804	3,607
Other	14	3
Valuation allowances	(184)	(152)
Total deferred tax assets	4,556	5,480
Deferred tax liabilities		
Property, plant and equipment	177	143
Other	27	14
Total deferred tax liabilities	204	157
Net deferred tax assets	$4,352	$5,323

Deferred Tax Assets and Valuation Allowances: The step-up in tax basis from the Merger Transactions in November 2014 resulted in a deferred tax asset, primarily related to our investment in KMP. As book earnings from our investment in KMP are projected to exceed taxable income (primarily as a result of the partnership's tax depreciation in excess of book depreciation), the deferred tax asset related to our investment in KMP is expected to be fully realized.

We recorded a full valuation allowance of $61 million against the deferred tax asset at December 31, 2014 related to our investment in NGPL as we concluded it was no longer realizable.

We increased our valuation allowances in 2016 by $32 million, primarily due to $18 million for our foreign tax credits, $10 million for foreign net operating losses, and $4 million for capital losses for which we do not expect to realize a future tax benefit.

We have deferred tax assets of $1,128 million related to net operating loss carryovers, $175 million related to alternative minimum and foreign tax credits, $4 million related to capital loss carryovers and $123 million of valuation allowances related to these deferred tax assets at December 31, 2016. As of December 31, 2015, we had deferred tax assets of $1,005 million related to net operating loss carryovers, $339 million related to alternative minimum and foreign tax credits, and valuation allowances related to these deferred tax assets of $91 million. We expect to generate taxable income beginning in 2020 and utilize all federal net operating loss carryforwards and alternative minimum tax carryforwards by the end of 2025.

Our alternative minimum tax credit carryforwards decreased by $151 million in 2016 as a result of our decision to elect to forgo bonus depreciation on property placed in service in that year. Code Section 168(k)(4) allows for corporate taxpayers with minimum tax credit carryforwards to forgo bonus depreciation and accelerate their use of the credits to reduce tax liability in that same tax year if the amount of the allowable credit exceeds the taxpayer's tax liability. The corporation may receive a cash refund of the excess notwithstanding that it may not otherwise be paying taxes.

In addition we have unrecorded deferred tax assets of $9 million as of December 31, 2016 related to net operating loss carryovers as a result of the delayed recognition of a windfall tax benefit related to share-based compensation. Upon the adoption of ASU 2016-09, the $9 million unrecorded deferred tax assets will be recorded through a cumulative-effect adjustment to retained earnings.

Expiration Periods for Deferred Tax Assets: As of December 31, 2016, we have U.S. federal net operating loss carryforwards of $2.7 billion, which will expire from 2018 - 2036; state losses of $3.0 billion which will expire from 2017 - 2036; and foreign losses of $183 million, of which approximately $137 million carries over indefinitely and $46 million expires from 2029 - 2036. We also have $153 million of federal alternative minimum tax credits which do not expire; and approximately $21 million of foreign tax credits, which will expire from 2017 - 2023. Use of a portion of our U.S. federal carryforwards is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation rules of Internal Revenue Service regulations. If certain substantial changes in our ownership occur, there would be an annual limitation on the amount of carryforwards that could be utilized.

Unrecognized Tax Benefits: We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based not only on the technical merits of the tax position based on tax law, but also the past administrative practices and precedents of the taxing authority. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate resolution.

A reconciliation of our gross unrecognized tax benefit excluding interest and penalties is as follows (in millions):

	Year Ended December 31,		
	2016	2015	2014
Balance at beginning of period	$148	$189	$209
Additions based on current year tax positions	3	4	12
Additions based on prior year tax positions	7	—	—
Reductions based on prior year tax positions	(1)	(6)	(3)
Reductions based on settlements with taxing authority	(26)	(25)	(24)
Reductions due to lapse in statute of limitations	(9)	(14)	(5)
Balance at end of period	$122	$148	$189

We recognize interest and/or penalties related to income tax matters in income tax expense. We recognized tax expense of $2 million and a benefit of $4 million and $1 million at December 31, 2016, 2015, and 2014, respectively. As of December 31, 2016, 2015, and 2014, we had $28 million, $24 million and $28 million, respectively, of accrued interest. We had no accrued penalties as of December 31, 2016 and $2 million in accrued penalties as of both December 31, 2015 and 2014. All of the $122 million of unrecognized tax benefits, if recognized, would affect our effective tax rate in future periods. In addition, we believe it is reasonably possible that our liability for unrecognized tax benefits will increase by approximately $2 million during the next year to approximately $124 million, primarily due to additions for state filing positions taken in prior years.

We are subject to taxation, and have tax years open to examination for the periods 2011-2015 in the U.S., 2002-2015 in various states and 2007-2015 in various foreign jurisdictions.

6. Property, Plant and Equipment, net

Classes and Depreciation

As of December 31, 2016 and 2015, our property, plant and equipment, net consisted of the following (in millions):

	December 31,	
	2016	2015
Pipelines (Natural gas, liquids, crude oil and CO_2)	$19,341	$19,855
Equipment (Natural gas, liquids, crude oil, CO_2, and terminals)	23,298	22,979
Other(a)	4,780	4,719
Accumulated depreciation, depletion and amortization	(12,306)	(10,851)
	35,113	36,702
Land and land rights-of-way	1,431	1,450
Construction work in process	2,161	2,395
Property, plant and equipment, net	$38,705	$40,547

(a) Includes buildings, computer and communication equipment, vessels, linefill and other.

As of December 31, 2016 and 2015, property, plant and equipment, net included $12,900 million and $16,089 million, respectively, of assets which were regulated by either the FERC or the NEB. Depreciation, depletion, and amortization expense charged against property, plant and equipment was $1,970 million, $2,059 million, and $1,862 million for the years ended December 31, 2016, 2015, and 2014, respectively.

Asset Retirement Obligations

As of December 31, 2016 and 2015, we recognized asset retirement obligations in the aggregate amount of $193 million and $215 million, respectively, of which $9 million were classified as current for each respective period. The majority of our asset retirement obligations are associated with our CO2 business segment, where we are required to plug and abandon oil and gas wells that have been removed from service and to remove the surface wellhead equipment and compressors.

7. Investments

Our investments primarily consist of equity investments where we hold significant influence over investee actions and for which we apply the equity method of accounting. As of December 31, 2016 and 2015, our investments consisted of the following (in millions):

	December 31,	
	2016	2015
Citrus Corporation	$1,709	$1,719
SNG	1,505	—
Ruby	798	1,093
Gulf LNG Holdings Group, LLC	485	516
NGPL Holdings LLC	475	153
Plantation Pipe Line Company	333	327
EagleHawk	329	348
MEP	328	713
Red Cedar Gathering Company	191	185
Watco Companies, LLC	180	201
Double Eagle Pipeline LLC	151	158
FEP	101	116
Liberty Pipeline Group LLC	75	79
Bear Creek Storage	61	—
Sierrita Gas Pipeline LLC	57	60
Utopia Holding LLC	55	—
Fort Union Gas Gathering L.L.C.	25	50
Parkway Pipeline LLC	—	131
All others	169	183
Total equity investments	7,027	6,032
Bond investments	—	8
Total investments	$7,027	$6,040

As shown in the table above, our significant equity investments, as of December 31, 2016 consisted of the following:

- Citrus Corporation—We own a 50% interest in Citrus Corporation, the sole owner of Florida Gas Transmission Company, L.L.C. (Florida Gas). Florida Gas transports natural gas to cogeneration facilities, electric utilities, independent power producers, municipal generators, and local distribution companies through a 5,300-mile natural gas pipeline. Energy Transfer Partners L.P. operates Florida Gas and owns the remaining 50% interest in Citrus;
-

SNG—Effective September 1, 2016, we operate SNG and own a 50% interest in SNG; and Evergreen Enterprise Holdings, LLC, a subsidiary of Southern Company, owns the remaining 50% interest.

- Ruby—We operate Ruby and own the common interest in Ruby, the sole owner of the Ruby Pipeline natural gas transmission system. Veresen Inc. owns the remaining interest in Ruby in the form of a convertible preferred interest. If Veresen converted its preferred interest into common interest, we and Veresen would each own a 50% common interest in Ruby;
- Gulf LNG Holdings Group, LLC—We operate Gulf LNG Holdings Group, LLC and own a 50% interest in Gulf LNG Holdings Group, LLC, the owner of a LNG receiving, storage and regasification terminal near Pascagoula, Mississippi, as well as pipeline facilities to deliver vaporized natural gas into third party pipelines for delivery into various markets around the country. The remaining 50% interest is owned by a variety of investment entities including subsidiaries of GE Financial Services and The Blackstone Group L.P.;
- NGPL Holdings LLC— We operate NGPL Holdings LLC and own a 50% interest in NGPL Holdings LLC, the indirect owner of NGPL and certain affiliates, collectively referred to in this report as NGPL, a major interstate natural gas pipeline and storage system. The remaining 50% interest is owned by Brookfield;
- Plantation—We operate Plantation and own a 51.17% interest in Plantation, the sole owner of the Plantation refined petroleum products pipeline system. A subsidiary of Exxon Mobil Corporation owns the remaining interest. Each investor has an equal number of directors on Plantation's board of directors, and board approval is required for certain corporate actions that are considered substantive participating rights; therefore, we do not control Plantation, and account for the investment under the equity method;
- BHP Billiton Petroleum (Eagle Ford) LLC, (EagleHawk)—We own a 25% interest in EagleHawk, the sole owner of natural gas and condensate gathering systems serving the producers of the Eagle Ford shale formation. A subsidiary of BHP Billiton Petroleum operates EagleHawk and owns the remaining 75% ownership interest;
- MEP—We operate MEP and own a 50% interest in MEP, the sole owner of the Midcontinent Express natural gas pipeline system. The remaining 50% ownership interest is owned by subsidiaries of Energy Transfer Partners L.P.;
- Red Cedar Gathering Company—We own a 49% interest in Red Cedar Gathering Company, the sole owner of the Red Cedar natural gas gathering, compression and treating system. The Southern Ute Indian Tribe owns the remaining 51% interest and serves as operator of Red Cedar;
- Watco Companies, LLC—We hold a preferred and common equity investment in Watco Companies, LLC, the largest privately held short line railroad company in the U.S. We own 100,000 Class A and 50,000 Class B preferred shares and pursuant to the terms of the investment, receive priority, cumulative cash and stock distributions from the preferred shares at a rate of 3.25% and 3.00% per quarter, respectively, and participate partially in additional profit distributions at a rate equal to 0.4%. Neither class holds any voting powers, but do provide us certain approval rights, including the right to appoint one of the members to Watco's board of managers. In addition to the senior interests, we also hold approximately 13,000 common equity units, which represents a 3.4% common ownership that is accounted for under the equity method of accounting;
- Double Eagle Pipeline LLC - We own a 50% equity interest in Double Eagle Pipeline LLC. The remaining 50% interest is owned by Magellan Midstream Partners;
- FEP —We own a 50% interest in FEP, the sole owner of the Fayetteville Express natural gas pipeline system. Energy Transfer Partners, L.P. owns the remaining 50% interest and serves as operator of FEP;
- Liberty Pipeline Group, LLC (Liberty) —We own a 50% interest in Liberty. ETC NGL Transport, LLC, a subsidiary of Energy Transfer Partners, L.P. owns the remaining 50% interest and serves as operator of Liberty;
- Bear Creek Storage—We own a 50% interest in Bear Creek through TGP, one of our wholly owned subsidiaries. SNG owns the remaining 50% interest;
- Sierrita Gas Pipeline LLC — We operate Sierrita Gas Pipeline LLC and own a 35% equity interest in the Sierrita Gas Pipeline LLC. MGI Enterprises U.S. LLC, a subsidiary of PEMEX, owns 35%; and MIT Pipeline Investment Americas, Inc., a subsidiary of Mitsui & Co., Ltd, owns 30%;
- Utopia Holding L.L.C. — We operate Utopia Holding L.L.C. and own a 50% interest in Utopia Holding L.L.C. after the sale of 50% of our interest to Riverstone Investment Group LLC on June 28, 2016;
- Fort Union Gas Gathering LLC—We own a 37.04% equity interest in the Fort Union Gas Gathering LLC. Crestone Powder River LLC, a subsidiary of ONEOK Partners L.P., owns 37.04%; Powder River Midstream, LLC owns 11.11%; and Western Gas Wyoming, LLC owns the remaining 14.81%. Western Gas Resources, Inc. serves as

operator of Fort Union Gas Gathering LLC;

- Parkway Pipeline LLC —Prior to the sale of our interest in Parkway, we operated and owned a 50% interest in Parkway Pipeline LLC, the sole owner of the Parkway Pipeline refined petroleum products pipeline system. Valero Energy Corp. owns the remaining 50% interest;
- Cortez Pipeline Company—We operate the Cortez carbon dioxide pipeline system, and as of December 31, 2016, we owned a 50% interest in, the Cortez Pipeline Company, the sole owner of the Cortez carbon dioxide pipeline system.

Our earnings (losses) from equity investments were as follows (in millions):

	Year Ended December 31,		
	2016	2015	2014
Citrus Corporation	$ 102	$ 96	$ 97
SNG	58	—	—
FEP	51	55	55
Gulf LNG Holdings Group, LLC	48	49	48
MEP	40	45	45
Plantation Pipe Line Company	37	29	29
Watco Companies, LLC	25	16	13
Red Cedar Gathering Company	24	26	33
Cortez Pipeline Company(a)	24	(3)	25
Ruby	15	18	15
Parkway Pipeline LLC	14	5	8
NGPL Holdings LLC	12	—	—
Liberty Pipeline Group LLC	11	9	6
EagleHawk	10	24	(7)
Sierrita Gas Pipeline LLC	7	9	3
Double Eagle Pipeline LLC	5	3	(1)
Bear Creek Storage	2	—	—
Fort Union Gas Gathering L.L.C.(b)	1	16	16
All others	11	17	21
Total earnings from equity investments	$ 497	$ 414	$ 406
Amortization of excess costs	(59)	(51)	(45)

(a) 2016 and 2015 amounts include $9 million and $26 million, respectively, representing our share of a non-cash impairment charge (pre-tax) recorded by Cortez Pipeline Company.
(b) 2016 amount includes non-cash impairment charges of $7 million (pre-tax) related to our investment.

Summarized combined financial information for our significant equity investments (listed or described above) is reported below (in millions; amounts represent 100% of investee financial information):

	Year Ended December 31,		
Income Statement	2016	2015	2014
Revenues	$ 4,084	$ 3,857	$ 3,829
Costs and expenses	3,056	3,408	3,063
Net income	$ 1,028	$ 449	$ 766

	December 31,	
Balance Sheet	2016	2015
Current assets	$ 892	$ 811
Non-current assets	22,170	19,745
Current liabilities	3,532	1,009
Non-current liabilities	9,187	11,227
Partners'/owners' equity	10,343	8,320

8. Goodwill

Changes in the amounts of our goodwill for each of the years ended December 31, 2016 and 2015 are summarized by reporting unit as follows (in millions):

	Natural Gas Pipelines Regulated	Natural Gas Pipelines Non-Regulated	CO2	Products Pipelines	Products Pipelines Terminals	Terminals	Kinder Morgan Canada	Total
Historical Goodwill	$ 17,527	$ 5,719	$ 1,528	$ 1,908	$ 221	$ 1,573	$ 591	$ 29,067
Accumulated impairment losses	(1,643)	(447)	—	(1,197)	(70)	(679)	(377)	(4,413)
December 31, 2014	15,884	5,272	1,528	711	151	894	214	24,654
Acquisitions(a)	—	93	—	217	—	11	—	321
Currency translation	—	—	—	—	—	—	(35)	(35)
Impairment	—	(1,150)	—	—	—	—	—	(1,150)
December 31, 2015	15,884	4,215	1,528	928	151	905	179	23,790
Currency translation	—	—	—	—	—	—	6	6
Divestitures(b)	(1,635)	—	—	—	—	(9)	—	(1,644)
December 31, 2016	$ 14,249	$ 4,215	$ 1,528	$ 928	$ 151	$ 896	$ 185	$ 22,152

(a) 2015 includes $93 million and $217 million, respectively, related to the February 2015 acquisition of Hiland by Natural Gas Pipelines Non-Regulated and Products Pipelines, and $7 million related to the February 2015 acquisition of Vopak terminal assets by Terminals, all of which are discussed in Note 3.

(b) 2016 includes $1,635 million related to the sale of a 50% interest in our SNG natural gas pipeline system by Natural Gas Pipelines Regulated to Southern Company and $9 million related to certain terminal divestitures.

Refer to Note 2 "Summary of Significant Accounting Policies—Goodwill" for a description of our accounting for goodwill and Note 4 for further discussion regarding impairments.

We determine the fair value of each reporting unit as of May 31 of each year based primarily on a market approach utilizing enterprise value to estimated EBITDA multiplies of comparable companies. The value of each reporting unit is determined on a stand-alone basis from the perspective of a market participant representing the price estimated to be received in a sale of the reporting unit in an orderly transaction between market participants at the measurement date. As of May 31, 2016, with the exception of our Natural Gas Pipelines Non-Regulated reporting unit, each of our reporting units indicated a fair value in excess of their respective carrying values. The amount of excess fair value over the carrying value ranged from approximately 9% for our Natural Gas Pipelines Regulated reporting unit to 80% for our Products Pipelines Terminals as of May 31, 2016. The results of our Step 2 analysis for our Natural Gas Pipelines Non-Regulated reporting unit did not indicate an impairment of goodwill and we did not identify any triggers for further impairment analysis during the remainder of the year.

Due to the effect of commodity prices on market conditions that impacted the energy sector, during the fourth quarter 2015, we conducted an interim test of the recoverability of goodwill as of December 31, 2015, and concluded that the goodwill of our Natural Gas Pipelines - Non-Regulated reporting unit was impaired by $1.15 billion.

For our Natural Gas Pipelines Non-Regulated and our CO2 reporting units, our May 31, 2016 annual test and our December 31, 2015 interim test included a discounted cash flow analysis (income approach) to evaluate the fair value of these reporting units to provide additional indication of fair value based on the present value of cash flows these reporting units are expected to generate in the future. We weighted the market and income approaches for these reporting units to arrive at an estimated fair value of these respective reporting units giving more weighting on the income approach and less on the market approach as we believed the values indicated using the income approach are more representative of the value that could be received from a market participant.

The fair value estimates of our reporting unit fair value, and in arriving at the fourth quarter 2015 impairment amount, were based on Level 3 inputs of the fair value hierarchy as discussed in Note 4.

A continued period of volatile commodity prices could result in further deterioration of market multiples, comparable sales transactions prices, weighted average costs of capital, and our cash flow estimates. A significant unfavorable change to any one or combination of these factors would result in a change to the reporting unit fair values discussed above potentially resulting in additional impairments of long-lived assets, equity method investments, and/or goodwill. Such non-cash impairments could have a significant effect on our results of operations.

9. Debt

We classify our debt based on the contractual maturity dates of the underlying debt instruments. We defer costs associated with debt issuance over the applicable term. These costs are then amortized as interest expense in our accompanying consolidated statements of income.

The following table provides detail on the principal amount of our outstanding debt balances. The table amounts exclude all debt fair value adjustments, including debt discounts, premiums and issuance costs (in millions):

	December 31,	
	2016	2015
KMI		
Unsecured term loan facility, variable rate, due January 26, 2019(a)	$1,000	$—
Senior notes 1.50% through 8.25%, due 2016 through 2098(b)(c)	13,236	13,346
Credit facility expiring November 26, 2019	—	—
Commercial paper borrowings	—	—
KMP		
Senior notes, 2.65% through 9.00%, due 2016 through 2044(c)	19,485	19,985
TGP senior notes, 7.00% through 8.375%, due 2016 through 2037(a)(c)	1,540	1,790
EPNG senior notes, 5.95% through 8.625%, due 2017 through 2032(c)	1,115	1,115
Copano senior notes, 7.125%, due April 1, 2021(c)(d)	—	332
CIG senior notes, 4.15% through 6.85%, due 2026 through 2037(c)(e)	475	100
SNG notes, 4.40% through 8.00%, due 2017 through 2032(c)(f)	—	1,211
Other Subsidiary Borrowings (as obligor)		
Kinder Morgan Finance Company, LLC, senior notes, 5.70% through 6.40%, due 2016 through 2036(a)(c)	786	1,636
Hiland Partners Holdings LLC, senior notes, 5.50% and 7.25%, due 2020 and 2022(c)(g)	225	974
EPC Building, LLC, promissory note, 3.967%, due 2016 through 2035	433	443
Trust I preferred securities, 4.75%, due March 31, 2028(h)	221	221
KMGP, $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock(i)	100	100
Other miscellaneous debt(j)	285	300
Total debt – KMI and Subsidiaries	38,901	41,553
Less: Current portion of debt(a)(f)(k)	2,696	821
Total long-term debt – KMI and Subsidiaries(l)	$36,205	$40,732

(a) On January 26, 2016, we entered into a $1 billion three-year unsecured term loan facility with a variable interest rate, which is determined in the same manner as interest on our revolving credit facility borrowings. In January 2016, we repaid $850 million of maturing 5.70% senior notes, and in February 2016, we repaid $250 million of maturing 8.00% senior notes primarily using proceeds from the three-year term loan. Since we refinanced a portion of the maturing debt with proceeds from long-term debt, we classified $1 billion of the maturing debt within "Long-term debt" on our consolidated balance sheet as of December 31, 2015.

(b) Amounts include senior notes that are denominated in Euros and have been converted and are respectively reported above at the December 31, 2016 exchange rate of 1.0517 U.S. dollars per Euro and the December 31, 2015 exchange rate of 1.0862 U.S. dollars per Euro. For the year ended December 31, 2016, our debt decreased by $43 million as a result of the change in the exchange rate of U.S dollars per Euro. The decrease in debt due to the changes in exchange rates is offset by a corresponding change in the value of cross-currency swaps reflected in "Deferred charges and other assets" and " Other long-term liabilities and deferred credits" on our consolidated balance sheets. At the time of issuance, we entered into cross-currency swap agreements associated with these senior notes, effectively converting these Euro-denominated senior notes to U.S. dollars (see Note 14 "Risk Management—Foreign Currency Risk Management").

(c) Notes provide for the redemption at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date plus a make whole premium and are subject to a number of restrictions and covenants. The most restrictive of these include limitations on the incurrence of liens and limitations on sale-leaseback transactions.

(d) On September 30, 2016, we repaid the $332 million principal amount of 7.125% senior notes due 2021, plus accrued interest. We recognized a $28.3 million gain from the early extinguishment of debt, included within "Interest, net" on the accompanying consolidated statements of income for the year ended December 31, 2016 consisting of an $11.8 million premium on the debt repaid and a $40.1 million gain from the write-off of unamortized purchase accounting associated with the extinguished debt. Copano continues to be a subsidiary guarantor under a cross guarantee agreement (see Note 19).

(e) On August 16, 2016, CIG completed a private offering of $375 million in principal amount of 4.15% senior notes due August 15, 2026. The net proceeds of $372 million received from the offering were used to reduce debt incurred as the result of the repayment of CIG's senior notes that matured in 2015 and for general corporate purposes.

(f) Due to the September 1, 2016 sale of a 50% interest in SNG, we no longer consolidate SNG's accounts in our consolidated financial statements. As of the transaction date, SNG had $1,211 million of debt outstanding (including a current portion of $500 million).

(g) On October 1, 2016, a portion of the proceeds from the sale of a 50% interest in SNG was used to repay the $749 million principal amount of Hiland's 7.25% senior notes due 2020, plus accrued interest. We recognized a $17.3 million gain from the early extinguishment of debt, included within "Interest, net" on the accompanying consolidated statements of income for the year ended December 31, 2016 consisting of a $27.1 million premium on the debt repaid and a $44.4 million gain from the write-off of unamortized purchase accounting associated with the extinguished debt.

(h) Capital Trust I (Trust I), is a 100%-owned business trust that as of December 31, 2016, had 4.4 million of 4.75% trust convertible preferred securities outstanding (referred to as the Trust I Preferred Securities). Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4.75% convertible subordinated debentures, which are due 2028. Trust I's sole source of income is interest earned on these debentures. This interest income is used to pay distributions on the preferred securities. We provide a full and unconditional guarantee of the Trust I Preferred Securities. There are no significant restrictions from these securities on our ability to obtain funds from our subsidiaries by distribution, dividend or loan. The Trust I Preferred Securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4.75%, carry a liquidation value of $50 per security plus accrued and unpaid distributions and are convertible at any time prior to the close of business on March 31, 2028, at the option of the holder, into the following mixed consideration: (i) 0.7197 of a share of our Class P common stock; (ii) $25.18 in cash without interest; and (iii) 1.100 warrants to purchase a share of our Class P common stock. We have the right to redeem these Trust I Preferred Securities at any time. Because of the substantive conversion rights of the securities into the mixed consideration, we bifurcated the fair value of the Trust I Preferred Securities into debt and equity components and as of December 31, 2016, the outstanding balance of $221 million (of which $111 million was classified as current) was bifurcated between debt ($199 million) and equity ($22 million). During the years ended December 31, 2016 and 2015, 200 and 1,176,015, respectively, of Trust I Preferred Securities had been converted into (i) 143 and 846,369 shares of our Class P common stock; (ii) approximately $5,000 and $30 million in cash; and (iii) 220 and 1,293,615 in warrants, respectively.

(i) As of December 31, 2016 and 2015, KMGP had outstanding, 100,000 shares of its $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock due 2057. Since August 18, 2012, dividends on the preferred stock accumulate at a floating rate of the 3-month LIBOR plus 3.8975% and are payable quarterly in arrears, when and if declared by KMGP's board of directors, on February 18, May 18, August 18 and November 18 of each year, beginning November 18, 2012. The preferred stock has approval rights over a commencement of or filing of voluntary bankruptcy by KMP or its SFPP or Calnev subsidiaries.

(j) In conjunction with the construction of the Totem Gas Storage facility (Totem) and the High Plains pipeline (High Plains), CIG's joint venture partner in WYCO funded 50% of the construction costs. Upon project completion, the advances were converted into a financing obligation to WYCO. As of December 31, 2016, the principal amounts of the Totem and High Plains financing obligations were $71 million and $92 million, respectively, which will be paid in monthly installments through 2039 based on the initial lease term. The interest rate on these obligations is 15.5%, payable on a monthly basis.

(k) Amounts include outstanding credit facility and commercial paper borrowings and other debt maturing within 12 months. See “—Maturities of Debt” below.

(l) Excludes our “Debt fair value adjustments” which, as of December 31, 2016 and 2015, increased our combined debt balances by $1,149 million and $1,674 million, respectively. In addition to all unamortized debt discount/premium amounts, debt issuance costs and purchase accounting on our debt balances, our debt fair value adjustments also include amounts associated with the offsetting entry for hedged debt and any unamortized portion of proceeds received from the early termination of interest rate swap agreements. For further information about our debt fair value adjustments, see —“Debt Fair Value Adjustments” below.

We and substantially all of our wholly owned domestic subsidiaries are a party to a cross guarantee agreement whereby each party to the agreement unconditionally guarantees, jointly and severally, the payment of specified indebtedness of each other party to the agreement. Also, see Note 19.

Credit Facilities and Restrictive Covenants

On January 26, 2016, we increased the capacity of our revolving credit agreement, initially entered into during 2014, from $4.0 billion to $5.0 billion. The other terms of our revolving credit agreement remain the same. We also maintain a $4.0 billion commercial paper program through the private placement of short-term notes. The notes mature up to 270 days from the date of issue and are not redeemable or subject to voluntary prepayment by us prior to maturity. The notes are sold at par value less a discount representing an interest factor or if interest bearing, at par. Borrowings under our revolving credit facility can be used for working capital and other general corporate purposes and as a backup to our commercial paper program. Borrowings under our commercial paper program reduce the borrowings allowed under our credit facility.

Our credit facility borrowings bear interest at either (i) LIBOR plus an applicable margin ranging from 1.125% to 2.000% per annum based on our credit ratings or (ii) the greatest of (1) the Federal Funds Rate plus 0.5%; (2) the Prime Rate; and (3) LIBOR Rate for a one month eurodollar loan, plus 1%, plus, in each case, an applicable margin ranging from 0.125% to 1.00% per annum based on our credit rating. As of December 31, 2016, we were in compliance with all required financial covenants.

Our credit facility included the following restrictive covenants as of December 31, 2016:

- total debt divided by earnings before interest, income taxes, depreciation and amortization may not exceed:
- 6.50: 1.00, for the period ended on or prior to December 31, 2017; or
- 6.25: 1.00, for the period ended after December 31, 2017 and on or prior to December 31, 2018; or
- 6.00: 1.00, for the period ended after December 31, 2018;
- certain limitations on indebtedness, including payments and amendments;
- certain limitations on entering into mergers, consolidations, sales of assets and investments;
- limitations on granting liens; and
- prohibitions on making any dividend to shareholders if an event of default exists or would exist upon making such dividend.

As of December 31, 2016, we had no borrowings outstanding under our five-year $5.0 billion revolving credit facility, no borrowings outstanding under our $4.0 billion commercial paper program and $160 million in letters of credit. Our availability under our revolving credit facility as of December 31, 2016 was $4,840 million.

Current Portion of Debt

The primary components of our current portion of debt include the following significant series of long-term notes:

As of December 31, 2016	$600 million 6.00% notes due February 2017
	$300 million 7.50% notes due April 2017
	$355 million 5.95% notes due April 2017
	$786 million 7.00% notes due June 2017
	$500 million 2.00% notes due December 2017
As of December 31, 2015	$500 million 3.50% notes due March 2016

Long-term Debt Issuances, Repayments and Other Significant Changes in Debt

Following are significant long-term debt issuances, repayments and other significant changes made during 2016 and 2015:

	2016	2015
Issuances	$1.0 billion unsecured term loan facility due 2019	$800 million 5.05% notes due 2046
	$375 million 4.15% notes due 2026	$815 million 1.50% notes due 2022(a)
		$543 million 2.25% notes due 2027(a)
Repayments	$850 million 5.70% notes due 2016	$300 million 5.625% notes due 2015
	$500 million 3.50% notes due 2016	$250 million 5.15% notes due 2015
	$250 million 8.00% notes due 2016	$340 million 6.80% notes due 2015
	$67 million 8.25% notes due 2016	$375 million 4.10% notes due 2015
	$332 million 7.125% notes due 2021	
	$749 million 7.25% notes due 2020	
Other significant changes	$1,211 million reduction due to the deconsolidation of SNG, including a current portion of $500 million (see Note 3)	$1,413 million assumption of senior notes and other borrowings due to the Hiland acquisition of which $368 million was immediately paid down after closing (see Note 3)(b)

(a) Senior notes are denominated in Euros and are presented above in U.S. dollars at the exchange rate on the issuance date of 1.0862 U.S. dollars per Euro. We entered into cross-currency swap agreements associated with these senior notes (see Note 14—"Risk Management—Foreign Currency Risk Management").

(b) As of the February 13, 2015 Hiland acquisition date, we assumed (i) $975 million in principal amount of senior notes (which were valued at $1,043 million as of the acquisition date) and (ii) $368 million of other borrowings that were immediately repaid after closing, primarily consisting of borrowings outstanding under a revolving credit facility. The senior notes are subject to our cross guarantee agreement discussed in Note 19.

Maturities of Debt

The scheduled maturities of the outstanding debt balances, excluding debt fair value adjustments as of December 31, 2016, are summarized as follows (in millions):

Year	Total
2017	$2,696
2018	2,328
2019	3,820
2020	2,204
2021	2,422
Thereafter	25,431
Total	$38,901

Debt Fair Value Adjustments

The carrying value adjustment to debt securities whose fair value is being hedged is included within "Debt fair value adjustments" on our accompanying consolidated balance sheets. "Debt fair value adjustments" also include unamortized debt discount/premiums, purchase accounting debt fair value adjustments, unamortized portion of proceeds received from the early termination of interest rate swap agreements, and debt issuance costs. As of December 31, 2016, the weighted-average amortization period of the unamortized premium from the termination of interest rate swaps was approximately 16 years. The

following table summarizes the "Debt fair value adjustments" included on our accompanying consolidated balance sheets (in millions):

	December 31,	
Debt Fair Value Adjustments	2016	2015
Purchase accounting debt fair value adjustments	$806	$1,135
Carrying value adjustment to hedged debt	220	380
Unamortized portion of proceeds received from the early termination of interest rate swap agreements	342	397
Unamortized debt discount/premiums	(80)	(86)
Unamortized debt issuance costs	(139)	(152)
Total debt fair value adjustments	$1,149	$1,674

Interest Rates, Interest Rate Swaps and Contingent Debt

The weighted average interest rate on all of our borrowings was 4.95% during 2016 and 4.92% during 2015. Information on our interest rate swaps is contained in Note 14. For information about our contingent debt agreements, see Note 13 "Commitments and Contingent Liabilities—Contingent Debt").

10. Share-based Compensation and Employee Benefits

Share-based Compensation

Class P Shares

Kinder Morgan, Inc. Amended and Restated Stock Compensation Plan for Non-Employee Directors

We have a Kinder Morgan, Inc. Amended and Restated Stock Compensation Plan for Non-Employee Directors, in which our eligible non-employee directors participate. The plan recognizes that the compensation paid to each eligible non-employee director is fixed by our board, generally annually, and that the compensation is payable in cash. Pursuant to the plan, in lieu of receiving some or all of the cash compensation, each eligible non-employee director may elect to receive shares of Class P common stock. Each election will be generally at or around the first board meeting in January of each calendar year and will be effective for the entire calendar year. An eligible director may make a new election each calendar year. The total number of shares of Class P common stock authorized under the plan is 250,000. During 2016, 2015 and 2014, we made restricted Class P common stock grants to our non-employee directors of 31,880, 9,580 and 6,210, respectively. These grants were valued at time of issuance at $400,000, $401,000 and $220,000, respectively. All of the restricted stock awards made to non-employee directors vest during a six-month period.

Kinder Morgan, Inc. 2015 Amended and Restated Stock Incentive Plan

The Kinder Morgan, Inc. 2015 Amended and Restated Stock Incentive Plan is an equity awards plan available to eligible employees. The following table sets forth a summary of activity and related balances of our restricted stock awards excluding that issued to non-employee directors (in millions, except share and per share amounts):

	Year Ended December 31, 2016		Year Ended December 31, 2015		Year Ended December 31, 2014	
	Shares	Weighted Average Grant Date Fair	Shares	Weighted Average Grant Date Fair	Shares	Weighted Average Grant Date

		Value		Value		Fair Value
Outstanding at beginning of period	7,645,105	$ 37.91	7,373,294	$ 37.63	6,382,885	$ 37.38
Granted	2,816,599	21.36	1,488,467	38.20	1,694,668	36.01
Vested	(1,226,652)	38.53	(817,797)	35.66	(460,032)	28.84
Forfeited	(196,915)	35.74	(398,859)	38.51	(244,227)	36.39
Outstanding at end of period	9,038,137	$ 32.72	7,645,105	$ 37.91	7,373,294	$ 37.63

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The intrinsic value of restricted stock awards vested during the years ended December 31, 2016, 2015 and 2014 was $25 million, $31 million and $17 million, respectively. Restricted stock awards made to employees have vesting periods ranging from 1 year with variable vesting dates to 10 years. Following is a summary of the future vesting of our outstanding restricted stock awards:

Year	Vesting of Restricted Shares
2017	1,476,832
2018	2,352,443
2019	4,358,728
2020	539,790
2021	199,850
Thereafter	110,494
Total Outstanding	9,038,137

The related compensation costs less estimated forfeitures is generally recognized ratably over the vesting period of the restricted stock awards. Upon vesting, the grants will be paid in our Class P common shares.

During 2016, 2015 and 2014, we recorded $66 million, $52 million and $51 million, respectively, in expense related to restricted stock awards and capitalized approximately $9 million, $15 million and $6 million, respectively. At December 31, 2016 and 2015, unrecognized restricted stock awards compensation costs, less estimated forfeitures, was approximately $133 million and $154 million, respectively.

Pension and Other Postretirement Benefit Plans

Savings Plan

We maintain a defined contribution plan covering eligible U.S. employees. We contribute 5% of eligible compensation for most of the plan participants. Certain plan participants’ contributions and Company contributions are based on collective bargaining agreements. The total expense for our savings plan was approximately $48 million, $46 million, and $42 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Pension Plans

Our U.S. pension plan is a defined benefit plan that covers substantially all of our U.S. employees and provides benefits under a cash balance formula. A participant in the cash balance plan accrues benefits through contribution credits based on a combination of age and years of service, times eligible compensation. Interest is also credited to the participant’s plan account. A participant becomes fully vested in the plan after three years, and may take a lump sum distribution upon termination of employment or retirement. Certain collectively bargained and grandfathered employees continue to accrue benefits through career pay or final pay formulas.

Two of our subsidiaries, Kinder Morgan Canada Inc. and Trans Mountain Pipeline Inc. (as general partner of Trans Mountain Pipeline L.P.), are sponsors of pension plans for eligible Canadian and Trans Mountain pipeline employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements (which provide pension benefits in excess of statutory limits) and defined contributory plans. Benefits under the defined benefit components accrue through career pay or final pay formulas. The net periodic benefit costs, contributions and liability amounts associated with our Canadian plans are not material to our consolidated income statements or balance sheets; however, we began to include the activity and balances associated with our Canadian plans (including our Canadian OPEB plans discussed below) in the following disclosures on a prospective basis beginning in 2016. The associated net periodic benefit costs for these combined Canadian plans of $12 million and $10 million for the years ended December 31, 2015 and 2014, respectively, were reported separately in prior years.

Other Postretirement Benefit Plans

We and certain of our U.S. subsidiaries provide other postretirement benefits (OPEB), including medical benefits for closed groups of retired employees and certain grandfathered employees and their dependents, and limited postretirement life insurance benefits for retired employees. Our Canadian subsidiaries also provide OPEB benefits to current and future retirees and their dependents. Medical benefits under these OPEB plans may be subject to deductibles, co-payment provisions, dollar caps and other limitations on the amount of employer costs, and we reserve the right to change these benefits. Effective January 1, 2014, the U.S. plans were amended to provide a fixed subsidy to post-age 65 Medicare eligible participants to purchase coverage through a retiree Medicare exchange.

Additionally, our subsidiary SFPP has incurred certain liabilities for postretirement benefits to certain current and former employees, their covered dependents, and their beneficiaries. However, the net periodic benefit costs, contributions and liability amounts associated with the SFPP postretirement benefit plan are not material to our consolidated income statements or balance sheets.

Benefit Obligation, Plan Assets and Funded Status. The following table provides information about our pension and OPEB plans as of and for each of the years ended December 31, 2016 and 2015 (in millions):

	Pension Benefits		OPEB	
	2016	2015	2016	2015
Change in benefit obligation:				
Benefit obligation at beginning of period	$2,654	$2,804	$509	$624
Service cost	36	33	1	—
Interest cost	89	99	16	21
Actuarial loss (gain)	127	(109)	(42)	(101)
Benefits paid	(180)	(173)	(41)	(39)
Participant contributions	3	—	2	2
Medicare Part D subsidy receipts	—	—	1	2
Exchange rate changes	4	—	1	—
Other(a)	151	—	26	—
Benefit obligation at end of period	2,884	2,654	473	509
Change in plan assets:				
Fair value of plan assets at beginning of period	2,050	2,377	325	389
Actual return (loss) on plan assets	157	(204)	29	(45)
Employer contributions	8	50	16	16
Participant contributions	3	—	2	2
Medicare Part D subsidy receipts	—	—	1	2
Benefits paid	(180)	(173)	(41)	(39)
Exchange rate changes	3	—	—	—
Other(a)	119	—	—	—
Fair value of plan assets at end of period	2,160	2,050	332	325
Funded status - net liability at December 31,	$(724)	$(604)	$(141)	$(184)

(a) 2016 amounts represent December 31, 2015 balances associated with our Canadian pension and OPEB plans and Plantation Pipeline OPEB plan for prospective inclusion in these disclosures, which associated net periodic benefit costs were reported separately in prior years.

Components of Funded Status. The following table details the amounts recognized in our balance sheet at December 31, 2016 and 2015 related to our pension and OPEB plans (in millions):

	Pension Benefits		OPEB	
	2016	2015	2016	2015
Non-current benefit asset(a)	$—	$—	$153	$139
Current benefit liability	—	—	(16)	(16)
Non-current benefit liability(a)	(724)	(604)	(278)	(307)
Funded status - net liability at December 31,	$(724)	$(604)	$(141)	$(184)

(a) 2016 OPEB amount includes $29 million of non-current benefit assets and $12 million of non-current benefit liabilities related to plans we sponsor which are associated with employee services provided to unconsolidated joint ventures, and for which we have recorded an offsetting related party deferred charge/credit.

Components of Accumulated Other Comprehensive (Loss) Income. The following table details the amounts of pre-tax accumulated other comprehensive (loss) income at December 31, 2016 and 2015 related to our pension and OPEB plans which are included on our accompanying consolidated balance sheets, including the portion attributable to our noncontrolling interests, (in millions):

	Pension Benefits		OPEB	
	2016	2015	2016	2015
Unrecognized net actuarial (loss) gain	$(682)	$(558)	$69	$ 23
Unrecognized prior service (cost) credit	(5)	(4)	18	19
Accumulated other comprehensive (loss) income	$(687)	$(562)	$87	$ 42

We anticipate that approximately $44 million of pre-tax accumulated other comprehensive loss will be recognized as part of our net periodic benefit cost in 2017, including approximately $45 million of unrecognized net actuarial loss and approximately $1 million of unrecognized prior service credit.

Our accumulated benefit obligation for our pension plans was $2,834 million and $2,615 million at December 31, 2016 and 2015, respectively.

Our accumulated postretirement benefit obligation for our OPEB plans, whose accumulated postretirement benefit obligations exceeded the fair value of plan assets, was $415 million and $444 million at December 31, 2016 and 2015, respectively. The fair value of these plans' assets was approximately $121 million at both December 31, 2016 and 2015.

Plan Assets. The investment policies and strategies are established by the Fiduciary Committee for the assets of each of the U.S. pension and OPEB plans and by the Pension Committee for the assets of the Canadian pension plans (the "Committees"), which are responsible for investment decisions and management oversight of the plans. The stated philosophy of each of the Committees is to manage these assets in a manner consistent with the purpose for which the plans were established and the time frame over which the plans' obligations need to be met. The objectives of the investment management program are to (1) meet or exceed plan actuarial earnings assumptions over the long term and (2) provide a reasonable return on assets within established risk tolerance guidelines and to maintain the liquidity needs of the plans with the goal of paying benefit and expense obligations when due. In seeking to meet these objectives, the Committees recognize that prudent investing requires taking reasonable risks in order to raise the likelihood of achieving the targeted investment returns. In order to reduce portfolio risk and volatility, the Committees have each adopted a strategy of using multiple asset classes.

As of December 31, 2016, the allowable range for asset allocations in effect for our U.S. pension plan were 34% to 59% equity, 37% to 57% fixed income, 0% to 5% cash, 0% to 2% alternative investments and 0% to 10% company securities (KMI Class P common stock). As of December 31, 2016, the allowable range for asset allocations in effect for our U.S. retiree medical and retiree life insurance plans were 15% to 55% equity, 15% to 47% fixed income, 0% to 20% cash and 13% to 39% master limited partnerships. As of December 31, 2016, the allowable range for asset allocations in effect for our Canadian pension plans were 0% to 55% equity and 45% to 100% fixed income.

Below are the details of our pension and OPEB plan assets by class and a description of the valuation methodologies used for assets measured at fair value.

- Level 1 assets' fair values are based on quoted market prices for the instruments in actively traded markets. Included in this level are cash, equities, exchange traded mutual funds and master limited partnerships. These investments are valued at the closing price reported on the active market on which the individual securities are traded.

- Level 2 assets' fair values are primarily based on pricing data representative of quoted prices for similar assets in active markets (or identical assets in less active markets). Included in this level are short-term investment funds, fixed income securities and derivatives. Short-term investment funds are valued at amortized cost, which approximates fair value. The fixed income securities' fair values are primarily based on an evaluated price which is based on a compilation of primarily observable market information or a broker quote in a non-active market. Derivatives are exchange-traded through clearinghouses and are valued based on these prices.

- Level 3 assets' fair values are calculated using valuation techniques that require inputs that are both significant to the fair value measurement and are unobservable, or are similar to Level 2 assets. Included in this level are guaranteed insurance contracts and immediate participation guarantee contracts. These contracts are valued at contract value, which approximates fair value.

Plan assets with fair values that are based on the net asset value per share, or its equivalent (NAV), as reported by the issuers are determined based on the fair value of the underlying securities as of the valuation date and include common/collective trust funds, private investment funds, limited partnerships, and fixed income trusts. These amounts are not categorized within the fair value hierarchy described above, but are separately identified in the following tables.

Listed below are the fair values of our pension and OPEB plans' assets that are recorded at fair value by class and categorized by fair value measurement used at December 31, 2016 and 2015 (in millions):

	Pension Assets							
	2016				2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Measured within fair value hierarchy								
Cash	$10	$—	$ —	$10	$15	$—	$ —	$15
Short-term investment funds	—	100	—	100	—	110	—	110
Mutual funds(a)	197	—	—	197	70	—	—	70
Equities(b)	283	—	—	283	271	—	—	271
Fixed income securities	—	428	—	428	—	449	—	449
Immediate participation guarantee contract	—	—	16	16	—	—	15	15
Derivatives	—	(2)	—	(2)	—	(14)	—	(14)
Subtotal	$490	$526	$ 16	1,032	$356	$545	$ 15	916
Measured at NAV(c)								
Common/collective trusts(d)				829				775
Private investment funds(e)				290				347
Private limited partnerships(f)				9				12
Subtotal				1,128				1,134
Total plan assets fair value				$2,160				$2,050

(a) For 2016 and 2015, this category includes mutual funds which are invested in equity.
(b) Plan assets include $126 million and $91 million of KMI Class P common stock for 2016 and 2015, respectively.
(c) Plan assets for which fair value was measured using NAV as a practical expedient.
(d) Common/collective trust funds were invested in approximately 39% fixed income and 61% equity in 2016 and 45% fixed income and 55% equity in 2015.
(e) Private investment funds were invested in approximately 54% fixed income and 46% equity in 2016 and 46% fixed income and 54% equity in 2015.
(f) Private limited partnerships were invested in real estate, venture and buyout funds for 2016 and 2015.

	OPEB Assets							
	2016				2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Measured within fair value hierarchy								
Short-term investment funds	$—	$ 15	$ —	$15	$—	$ 16	$ —	$16
Equities	11	—	—	11	8	—	—	8
Master limited partnerships	57	—	—	57	51	—	—	51
Guaranteed insurance contracts	—	—	47	47	—	—	49	49
Mutual funds	1	—	—	1	1	—	—	1
Subtotal	$69	$ 15	$ 47	131	$60	$ 16	$ 49	125
Measured at NAV(a)								
Common/collective trusts(b)				68				71
Fixed income trusts				64				58
Limited partnerships(c)				69				71
Subtotal				201				200
Total plan assets fair value				$332				$325

(a) Plan assets for which fair value was measured using NAV as a practical expedient.
(b) Common/collective trust funds which are invested in approximately 72% equity and 28% fixed income securities for 2016 and 67% equity and 33% fixed income securities for 2015.
(c) For 2016 and 2015, limited partnerships were invested in global equity securities.

The following tables present the changes in our pension and OPEB plans' assets included in Level 3 for the years ended December 31, 2016 and 2015 (in millions):

	Pension Assets				
	Balance at Beginning of Period	Transfers In (Out)	Realized and Unrealized Gains (Losses), net	Purchases (Sales), net	Balance at End of Period
2016					
Insurance contracts	$15	$ —	$ 1	$ —	$ 16
2015					
Insurance contracts	$15	$ —	$ —	$ —	$ 15

	OPEB Assets				
	Balance at Beginning of Period	Transfers In (Out)	Realized and Unrealized Gains (Losses), net	Purchases (Sales), net	Balance at End of Period
2016					
Insurance contracts	$49	$ —	$ (2)	$ —	$ 47
2015					
Insurance contracts	$51	$ —	$ (1)	$ (1)	$ 49

Changes in the underlying value of Level 3 assets due to the effect of changes of fair value were immaterial for the years ended December 31, 2016 and 2015.

Expected Payment of Future Benefits and Employer Contributions. As of December 31, 2016, we expect to make the following benefit payments under our plans (in millions):

Fiscal year	Pension Benefits	OPEB(a)
2017	$ 235	$ 39
2018	237	38
2019	232	39
2020	231	37
2021	220	37
2022 - 2026	1,016	168

(a) Includes a reduction of approximately $3 million in each of the years 2017 - 2021 and approximately $16 million in aggregate for 2022 - 2026 for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

In 2017, we expect to contribute approximately $22 million to our U.S. pension plan and $7 million, net of anticipated subsidies, to our U.S. OPEB plans. In 2017, we expect to contribute approximately $8 million to our Canadian pension plans and $1 million to our Canadian OPEB plan.

Actuarial Assumptions and Sensitivity Analysis. Benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining our benefit obligation and net benefit costs of our pension and OPEB plans for 2016, 2015 and 2014:

	Pension Benefits			OPEB		
	2016	2015	2014	2016	2015	2014
Assumptions related to benefit obligations:						
Discount rate	3.83%	4.05%	3.66%	3.69%	3.91%	3.56%
Rate of compensation increase	3.52%	3.50%	4.50%	n/a	n/a	n/a
Assumptions related to benefit costs:						
Discount rate for benefit obligations	4.05%	3.66%	4.45%	3.91%	3.56%	4.34%
Discount rate for interest on benefit obligations	3.24%	3.66%	4.45%	3.18%	3.56%	4.34%
Discount rate for service cost	4.15%	3.66%	4.45%	4.36%	3.56%	4.34%
Discount rate for interest on service cost	3.50%	3.66%	4.45%	4.17%	3.56%	4.34%
Expected return on plan assets(a)	7.31%	7.50%	7.50%	7.07%	7.08%	7.43%
Rate of compensation increase	3.51%	4.50%	3.50%	n/a	n/a	n/a

(a) The expected return on plan assets listed in the table above is a pre-tax rate of return based on our targeted portfolio of investments. For the OPEB assets subject to unrelated business income taxes (UBIT), we utilize an after-tax expected return on plan assets to determine our benefit costs, which is based on a UBIT rate of 21% for 2016, 2015 and 2014.

For years prior to 2016, we selected our discount rates by matching the timing and amount of our expected future benefit payments for our pension and other postretirement benefit obligations to the average yields of various high-quality bonds with corresponding maturities. Effective January 1, 2016, we changed our estimate of the service and interest cost components of net periodic benefit cost (credit) for our pension and other postretirement benefit plans. The new estimate utilizes a full yield curve approach in the estimation of these components by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to their underlying projected cash flows. The new estimate provides a more precise measurement of service and interest costs by improving the correlation between projected benefit cash flows and their corresponding spot rates. The change did not affect the measurement of our pension and postretirement benefit obligations and it was accounted for as a change in accounting estimate, which was applied prospectively. The expected long-term rates of return on plan assets were determined by combining a review of the historical returns realized within the portfolio, the investment strategy included in the plans' investment policy, and capital market projections for the asset classes in which the portfolio is invested and the target weightings of each asset class.

Actuarial estimates for our OPEB plans assumed a weighted-average annual rate of increase in the per capita cost of covered health care benefits of 9.30%, gradually decreasing to 4.54% by the year 2038. Assumed health care cost trends have a significant effect on the amounts reported for OPEB plans. A one-percentage point change in assumed health care cost trends would have the following effects as of December 31, 2016 and 2015 (in millions):

	2016	2015
One-percentage point increase:		
Aggregate of service cost and interest cost	$1	$2
Accumulated postretirement benefit obligation	27	31
One-percentage point decrease:		
Aggregate of service cost and interest cost	$(1)	$(1)
Accumulated postretirement benefit obligation	(23)	(27)

Components of Net Benefit Cost and Other Amounts Recognized in Other Comprehensive Income. For each of the years ended December 31, the components of net benefit cost and other amounts recognized in pre-tax other comprehensive income related to our pension and OPEB plans are as follows (in millions):

	Pension Benefits			OPEB		
	2016	2015	2014	2016	2015	2014
Components of net benefit cost:						
Service cost	$36	$33	$21	$1	$—	$—
Interest cost	89	99	112	16	21	25
Expected return on assets	(151)	(172)	(171)	(19)	(23)	(24)
Amortization of prior service cost (credit)	1	—	—	(3)	(3)	(2)
Amortization of net actuarial loss (gain)	35	5	—	—	1	(1)
Net benefit (credit) cost(a)	10	(35)	(38)	(5)	(4)	(2)
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss:						
Net loss (gain) arising during period	116	267	285	(48)	(49)	10
Prior service cost (credit) arising during period	—	—	—	—	—	—
Amortization or settlement recognition of net actuarial loss	(34)	(5)	—	—	(1)	—
Amortization of prior service credit	—	—	—	1	1	1
Exchange rate changes	1	—	—	—	—	—
Total recognized in total other comprehensive (income) loss	83	262	285	(47)	(49)	11
Total recognized in net benefit cost (credit) and other comprehensive (income) loss	$93	$227	$247	$(52)	$(53)	$9

(a) 2016 OPEB amount includes $4 million of net benefit credits related to plans that we sponsor that are associated with employee services provided to unconsolidated joint ventures. We charge or refund these costs or credits associated with these plans to the joint venture as an offset to our net benefit cost or credit and receive our proportionate share of these costs or credits through our share of the equity investee’s earnings.

Multiemployer Plans

We participate in several multi-employer pension plans for the benefit of employees who are union members. We do not administer these plans and contribute to them in accordance with the provisions of negotiated labor contracts. Other benefits include a self-insured health and welfare insurance plan and an employee health plan where employees may contribute for their dependents’ health care costs. Amounts charged to expense for these plans were approximately $8 million, $10 million and $13 million for the years ended December 31, 2016, 2015 and 2014, respectively. We consider the overall multi-employer pension plan liability exposure to be minimal in relation to the value of its total consolidated assets and net income.

11. Stockholders' Equity

Common Equity

As of December 31, 2016, our common equity consisted of our Class P common stock.

During the years 2014 through 2015, as authorized by our board of directors under various repurchase programs, we repurchased shares and warrants. As of December 31, 2016, we had $90 million of availability to repurchase warrants. During the years ended December 31, 2015 and 2014, we paid a total of $12 million and $98 million, respectively, for the repurchase of warrants. During the year ended December 31, 2014, we repurchased $94 million of our Class P shares.

On December 19, 2014, we entered into an equity distribution agreement authorizing us to issue and sell through or to the managers party thereto, as sales agents and/or principals, shares of our Class P common stock having an aggregate offering of up to $5.0 billion from time to time during the term of this agreement. During the year ended December 31, 2015, we issued and sold 102,614,508 shares of our Class P common stock pursuant to the equity distribution agreement resulting in net proceeds of $3.9 billion.

Common Dividends

Holders of our common stock participate in any dividend declared by our board of directors, subject to the rights of the holders of any outstanding preferred stock. The following table provides information about our per share dividends:

	Year Ended December 31,		
	2016	2015	2014
Per common share cash dividend declared for the period	$0.50	$1.605	$1.74
Per common share cash dividend paid in the period	0.50	1.93	1.70

On January 18, 2017, our board of directors declared a cash dividend of $0.125 per common share for the quarterly period ended December 31, 2016, which is payable on February 15, 2017 to shareholders of record as of February 1, 2017.

Warrants

Each of our warrants entitles the holder to purchase one share of our common stock for an exercise price of $40 per share, payable in cash or by cashless exercise, at any time until May 25, 2017. The table below sets forth the changes in our outstanding warrants:

	Warrants		
	2016	2015	2014
Beginning balance	293,263,797	298,135,976	347,933,107
Warrants issued with conversions of EP Trust I Preferred securities(a)	—	1,293,615	4,315
Warrants exercised	—	(71,268)	(18,040)
Warrants repurchased and canceled	—	(6,094,526)	(49,783,406)
Ending balance	293,263,797	293,263,797	298,135,976

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(a) See Note 9.

Mandatory Convertible Preferred Stock

On October 30, 2015, we completed an offering of 32,000,000 depositary shares, each of which represents a 1/20th interest in a share of our 1,600,000 shares of 9.75% Series A mandatory convertible preferred stock, with a liquidating preference of $1,000 per share (equal to a $50 liquidation preference per depositary share). Net proceeds, after underwriting discount and expenses, from the depositary share offering were approximately $1,541 million. The proceeds from the offering were used to repay borrowings under our revolving credit facility and commercial paper debt and for general corporate purposes.

Unless converted earlier at the option of the holders, on or around October 26, 2018, each share of convertible preferred stock will automatically convert into between 30.8800 and 36.2840 shares of our common stock (and, correspondingly, each depositary share will convert into between 1.5440 and 1.8142 shares of our common stock), subject to customary anti-dilution adjustments. The conversion range depends on the volume-weighted average price of our common stock over a 20 trading day averaging period immediately prior to that date (Applicable Market Value). If the Applicable Market Value for our common stock is greater than $32.38 or less than $27.56, the conversion rate per preferred stock will be 30.8800 or 36.2840, respectively. If the Applicable Market Value is between $32.38 and $27.56, the conversion rate per preferred stock will be between 30.8800 and 36.2840.

Preferred Dividends

Dividends on our mandatory convertible preferred stock are payable on a cumulative basis when, as and if declared by our board of directors (or an authorized committee thereof) at an annual rate of 9.75% of the liquidation preference of $1,000 per share on January 26, April 26, July 26 and October 26 of each year, commencing on January 26, 2016 to, and including, October 26, 2018. We may pay dividends in cash or, subject to certain limitations, in shares of common stock or any combination of cash and shares of common stock. The terms of the mandatory convertible preferred stock provide that, unless full cumulative dividends have been paid or set aside for payment on all outstanding mandatory convertible preferred stock for all prior dividend periods, no dividends may be declared or paid on common stock.

On October 19, 2016, our board of directors declared a cash dividend of $24.375000 per share of our mandatory convertible preferred stock (equivalent of $1.218750 per depositary share) for the period from and including October 26, 2016 through and including January 25, 2017, which was paid on January 26, 2017 to mandatory convertible preferred shareholders of record as of January 11, 2017.

Noncontrolling Interests

Contributions

Prior to the completion of the Merger Transactions on November 26, 2014, contributions from our noncontrolling interests consisted primarily of equity issuances to the public of common units or shares by KMP, EPB and KMR. Each of these subsidiaries had an equity distribution agreement in place which allowed the subsidiary to sell its equity interests from time to time through a designated sales agent. The equity distribution agreement provided the subsidiary with the right, but not the obligation to offer and sell its equity units or shares, at prices to be determined by market conditions. For the period from January 1, 2014 to November 26, 2014, KMP, EPB and KMR made equity issuances of 30 million units or shares, resulting in net proceeds of $1,695 million. These equity issuances had the associated effects of increasing our (i) noncontrolling interests by $1,640 million; (ii) accumulated deferred income taxes by $19 million; and (iii) additional paid-in capital by $36 million.

Distributions

The following table provides information about distributions from our noncontrolling interests (in millions except per unit and i-unit distribution amounts):

	Year Ended December 31, 2014
KMP(a)	
Per unit cash distribution declared for the period	$ 4.17
Per unit cash distribution paid in the period	$ 5.53
Cash distributions paid in the period to the public	$ 1,654
EPB(a)	
Per unit cash distribution declared for the period	$ 1.95
Per unit cash distribution paid in the period	$ 2.60

Cash distributions paid in the period to the public	$ 347
KMR(a)(b)	
Share distributions paid in the period to the public	7,794,183

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(a) As a result of the Merger Transactions, no distribution was declared starting with the fourth quarter of 2014. KMR's distributions were paid in the form of additional shares or fractions thereof calculated by dividing the KMP cash distribution per common unit by the average of the market closing prices of a KMR share determined for a ten-trading day period ending on the trading day immediately prior to the ex-dividend date for the shares.

(b) Represents share distributions made in the period to noncontrolling interests and excludes 1,127,712 of shares distributed in 2014 on KMR shares we directly and indirectly owned.

12. Related Party Transactions

Affiliate Balances

The following tables summarize our affiliate balance sheet balances and income statement activity (in millions):

	December 31,	
	2016	2015
Balance sheet location		
Accounts receivable, net	$37	$25
Other current assets	—	36
Deferred charges and other assets	10	—
	$47	$61
Current portion of debt	$6	$6
Accounts payable	28	22
Other current liabilities	9	10
Long-term debt	161	167
Other long-term liabilities and deferred credits	29	—
	$233	$205

	Year Ended December 31,		
	2016	2015	2014
Income statement location			
Revenues			
Services	$71	$72	$29
Product sales and other	71	71	86
	$142	$143	$115
Operating Costs, Expenses and Other			
Costs of sales	$38	$60	$74
Other operating expenses	75	55	57

Notes Receivable

Plantation
In March 2016, we received the final principal payment of $35 million for our proportionate share of a note receivable due from Plantation. We own a 51.17% equity interest in Plantation and the $35 million note receivable balance for our proportionate share of the note was included within “Other current assets” on our accompanying consolidated balance sheet as of December 31, 2015.

Subsequent Event

MEP Loan Agreement

On February 3, 2017 we renewed our $40 million loan agreement for an additional one-year term with MEP, our 50%-owned equity investee. The loan agreement allows us, at our sole option, to make loans from time to time to MEP to fund its working capital needs and for other LLC purposes. Borrowings under the loan agreement bear interest at a rate of one month LIBOR plus 1.50%, and all borrowings can be prepaid before maturity without penalty or premium. As of both December 31, 2016 and 2015 there was no amount outstanding pursuant to this loan agreement.

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13. Commitments and Contingent Liabilities

Leases and Rights-of-Way Obligations

The table below depicts future gross minimum rental commitments under our operating leases and rights-of-way obligations as of December 31, 2016 (in millions):

Year	Commitment
2017	$ 106
2018	94
2019	86
2020	75
2021	61
Thereafter	342
Total minimum payments	$ 764

The remaining terms on our operating leases, including probable elections to exercise renewal options, range from one to forty-one years. Total lease and rental expenses were $138 million, $143 million and $114 million for the years ended December 31, 2016, 2015 and 2014, respectively. The amount of capital leases included within "Property, plant and equipment, net" in our accompanying consolidated balance sheets as of December 31, 2016 and 2015 is not material to our consolidated balance sheets.

Contingent Debt

Our contingent debt disclosures pertain to certain types of guarantees or indemnifications we have made and cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote.

As of December 31, 2016 and 2015, our contingent debt obligations, as well as our obligations with respect to related letters of credit, totaled $1,179 million and $1,202 million, respectively. Both December 31, 2016 and 2015 amounts are primarily represented by our proportional share of the debt obligations of two equity investees. Under such guarantees we are severally liable for our percentage ownership share of these equity investees' debt issued in the event of their non-performance. Also included in our contingent debt obligations is a guarantee of the debt obligations of our 50%-owned investee, Cortez Pipeline Company. We are severally liable for 50% (our percentage ownership share) of the Cortez Pipeline Company debt which includes a $50 million credit facility and $100 million in bonds. In addition, we are liable for 100% of the debt issued by one of Cortez Pipeline Company's subsidiaries in the event of their non-performance which has a $100 million credit facility and $120 million private placement note to fund an expansion project.

Guarantees and Indemnifications

We are involved in joint ventures and other ownership arrangements that sometimes require financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes and environmental matters.

While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are also circumstances where the amount and duration are unlimited. Currently, we are not subject to any material requirements to perform under quantifiable arrangements, and we expect future requirements to perform under quantifiable arrangements will be immaterial. We are unable to estimate a maximum exposure for our guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

See Note 17 “Litigation, Environmental and Other Contingencies” for a description of matters that we have identified as contingencies requiring accrual of liabilities and/or disclosure, including any such matters arising under guarantee or indemnification agreements.

Commitment for Jones Act Trade Fleet Expansion

Under an August 2015 definitive construction agreement with Philly Tankers LLC, we are expected to have four more Jones Act tankers delivered by the end of 2017. Our obligation for payments due under the terms of this agreement total $383 million in 2017, of which, approximately $195 million relates to work not yet performed as of December 31, 2016.

14. Risk Management

Certain of our business activities expose us to risks associated with unfavorable changes in the market price of natural gas, NGL and crude oil. We also have exposure to interest rate and foreign currency risk as a result of the issuance of our debt obligations. Pursuant to our management's approved risk management policy, we use derivative contracts to hedge or reduce our exposure to certain of these risks. In addition, prior to May 2016, we had power forward and swap contracts related to legacy operations of acquired businesses.

Energy Commodity Price Risk Management

As of December 31, 2016, we had the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Net open position long/(short)	
Derivatives designated as hedging contracts		
Crude oil fixed price	(19.7)	MMBbl
Crude oil basis	(1.3)	MMBbl
Natural gas fixed price	(38.4)	Bcf
Natural gas basis	(19.3)	Bcf
Derivatives not designated as hedging contracts		
Crude oil fixed price	(1.7)	MMBbl
Crude oil basis	(0.1)	MMBbl
Natural gas fixed price	(5.2)	Bcf
Natural gas basis	(1.4)	Bcf
NGL and other fixed price	(5.0)	MMBbl

As of December 31, 2016, the maximum length of time over which we have hedged, for accounting purposes, our exposure to the variability in future cash flows associated with energy commodity price risk is through December 2020.

Interest Rate Risk Management

As of December 31, 2016, we had a combined notional principal amount of $9,775 million of fixed-to-variable interest rate swap agreements, all of which were designated as fair value hedges. As of December 31, 2015, we had a combined notional principal amount of $11,000 million of fixed-to-variable interest rate swap agreements, of which $9,700 million were designated as fair value hedges. All of our swap agreements effectively convert the interest expense associated with certain series of senior notes from fixed rates to variable rates based on an interest rate of LIBOR plus a spread and have termination dates that correspond to the maturity dates of the related series of senior notes. As of December 31, 2016, the maximum length of time over which we have hedged a portion of our exposure to the variability in the value of this debt due to interest rate risk is through March 15, 2035.

Foreign Currency Risk Management

In connection with the issuance of our Euro denominated senior notes in March 2015 (see Note 9), we entered into $1,358 million of cross-currency swap agreements to manage the related foreign currency risk by effectively converting all of the fixed-rate Euro denominated debt, including annual interest payments and the payment of principal at maturity, to U.S. dollar denominated debt at fixed rates equivalent to approximately 3.79% and 4.67% for the 7-year and 12-year senior notes, respectively. These cross-currency swaps are accounted for as cash flow hedges. The terms of the cross-currency swap agreements correspond to the related hedged senior notes, and such agreements have the same maturities as the hedged senior notes.

Fair Value of Derivative Contracts

The following table summarizes the fair values of our derivative contracts included on our accompanying consolidated balance sheets (in millions):

Fair Value of Derivative Contracts

	Location	Asset derivatives December 31, 2016 Fair value	Asset derivatives December 31, 2015 Fair value	Liability derivatives December 31, 2016 Fair value	Liability derivatives December 31, 2015 Fair value
Derivatives designated as hedging contracts					
Natural gas and crude derivative contracts	Fair value of derivative contracts/(Other current liabilities)	$ 101	$ 359	$ (57)	$ (13)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	70	244	(24)	—
Subtotal		171	603	(81)	(13)
Interest rate swap agreements	Fair value of derivative contracts/(Other current liabilities)	94	111	—	—
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	206	273	(57)	(9)
Subtotal		300	384	(57)	(9)
Cross-currency swap agreements	Fair value of derivative contracts/(Other current liabilities)	—	—	(7)	(6)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	—	(24)	(46)
Subtotal		—	—	(31)	(52)
Total		471	987	(169)	(74)
Derivatives not designated as hedging contracts					
Natural gas, crude, NGL and other derivative contracts	Fair value of derivative contracts/(Other current liabilities)	3	35	(29)	(1)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	—	(1)	—
Subtotal		3	35	(30)	(1)
Interest rate swap agreements	Fair value of derivative contracts/(Other current liabilities)	—	1	—	(11)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	—	—	(5)
Subtotal		—	1	—	(16)
Power derivative contracts	Fair value of derivative contracts/(Other current liabilities)	—	1	—	(17)
Subtotal		—	1	—	(17)
Total		3	37	(30)	(34)
Total derivatives		$ 474	$ 1,024	$ (199)	$ (108)

Effect of Derivative Contracts on the Income Statement

The following tables summarize the impact of our derivative contracts on our accompanying consolidated statements of income (in millions):

Derivatives in fair value hedging relationships	Location	Gain/(loss) recognized in income on derivatives and related hedged item		
		Year Ended December 31,		
		2016	2015	2014
Interest rate swap agreements	Interest, net	$ (180)	$ 25	$ 207
Hedged fixed rate debt	Interest, net	$ 160	$ (33)	$ (204)

Derivatives in cash flow hedging relationships	Gain/(loss) recognized in OCI on derivative (effective portion)(a)			Location	Gain/(loss) reclassified from Accumulated OCI into income (effective portion)(b)			Location	Gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)		
	Year Ended December 31,				Year Ended December 31,				Year Ended December 31,		
	2016	2015	2014		2016	2015	2014		2016	2015	2014
Energy commodity derivative contracts	$(115)	$201	$424	Revenues—Natural gas sales	$15	$54	$(1)	Revenues—Natural gas sales	$—	$ —	$ —
				Revenues—Product sales and other	148	236	26	Revenues—Product sales and other	(12)	2	11
				Costs of sales	(17)	(15)	4	Costs of sales	—	—	—
Interest rate swap agreements(c)	(2)	(4)	(15)	Interest, net	(3)	(3)	(4)	Interest, net	—	—	—
Cross-currency swap	13	(33)	—	Other, net	(27)	—	—	Other, net	—	—	—
Total	$(104)	$164	$409	Total	$116	$272	$25	Total	$(12)	$ 2	$ 11

(a) We expect to reclassify an approximate $8 million gain associated with cash flow hedge price risk management activities included in our accumulated other comprehensive loss balances as of December 31, 2016 into earnings during the next twelve months (when the associated forecasted transactions are also expected to occur), however, actual amounts reclassified into earnings could vary materially as a result of changes in market prices.

(b) Amounts reclassified were the result of the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchases actually occurred).

(c) Amounts represent our share of an equity investee's accumulated other comprehensive loss.

Derivatives not designated as accounting hedges	Location	Gain/(loss) recognized in income on derivatives Year Ended December 31,		
		2016	2015	2014
Energy commodity derivative contracts	Revenues—Natural gas sales	$ (10)	$ 17	$ (7)
	Revenues—Product sales and other	(26)	176	20
	Costs of sales	3	(2)	—
	Other (income) expense, net	—	—	(2)
Interest rate swap agreements	Interest, net	63	(15)	—
Total(a)		$ 30	$ 176	$ 11

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(a) For the years ended December 31, 2016 and 2015, includes an approximate gain of $73 million and $31 million, respectively, associated with natural gas, crude and NGL derivative contract settlements.

Credit Risks

In conjunction with certain derivative contracts, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of December 31, 2016 and 2015, we had $0 million and $2 million, respectively, of outstanding letters of credit supporting our commodity price risk management program. As of December 31, 2016, we had cash margins of $37 million posted by us with our counterparties as collateral and no amounts posted by our counterparties as collateral. As of December 31, 2015, we had no cash margins posted by us as collateral and cash margins of $37 million posted by our counterparties as collateral. We also use industry standard commercial agreements which allow for the netting of exposures associated with transactions executed under a single commercial agreement. Additionally, we generally utilize netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring the posting of additional collateral upon a decrease in our credit rating. As of December 31, 2016, based on our current mark to market positions and posted collateral, we estimate that if our credit rating were downgraded one notch we would be required to post $10 million of additional collateral and no additional collateral beyond this $10 million if we were downgraded two notches.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Loss
Cumulative revenues, expenses, gains and losses that under GAAP are included within our comprehensive income but excluded from our earnings are reported as "Accumulated other comprehensive loss" within "Stockholders' Equity" in our consolidated balance sheets. Changes in the components of our "Accumulated other comprehensive loss" not including non-controlling interests are summarized as follows (in millions):

	Net unrealized gains/(losses) on cash flow hedge derivatives	Foreign currency translation adjustments	Pension and other postretirement liability adjustments	Total Accumulated other comprehensive loss
Balance as of December 31, 2013	$ (3)	$ 2	$ (23)	$ (24)
Other comprehensive gain (loss) before reclassifications	254	(68)	(212)	(26)
Gains reclassified from accumulated other comprehensive loss	(22)	—	(1)	(23)
Impact of Merger Transactions (See Note 1)	98	(42)	—	56
Net current-period other comprehensive income (loss)	330	(110)	(213)	7
Balance as of December 31, 2014	327	(108)	(236)	(17)
Other comprehensive gain (loss) before reclassifications	164	(214)	(122)	(172)
Gains reclassified from accumulated other comprehensive loss	(272)	—	—	(272)
Net current-period other comprehensive loss	(108)	(214)	(122)	(444)
Balance as of December 31, 2015	219	(322)	(358)	(461)
Other comprehensive (loss) gain before reclassifications	(104)	34	(14)	(84)
Gains reclassified from accumulated other comprehensive loss	(116)	—	—	(116)
Net current-period other comprehensive (loss) income	(220)	34	(14)	(200)
Balance as of December 31, 2016	$ (1)	$ (288)	$ (372)	$ (661)

15. Fair Value of Financial Instruments

The fair values of our financial instruments are separated into three broad levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. Each fair value measurement must be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety.
The three broad levels of inputs defined by the fair value hierarchy are as follows:

- Level 1 Inputs—quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;
- Level 2 Inputs—inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability; and
- Level 3 Inputs—unobservable inputs for the asset or liability. These unobservable inputs reflect the entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability, and are developed based on the best information available in the circumstances (which might include the reporting entity's own data).

Fair Value of Derivative Contracts

The following two tables summarize the fair value measurements of our (i) energy commodity derivative contracts; (ii) interest rate swap agreements; and (iii) cross-currency swap agreements, based on the three levels established by the Codification (in millions). The tables also identify the impact of derivative contracts which we have elected to present on our accompanying consolidated balance sheets on a gross basis that are eligible for netting under master netting agreements.

	Balance sheet asset fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Cash collateral held(b)	Net amount
As of December 31, 2016							
Energy commodity derivative contracts(a)	$6	$168	$ —	$ 174	$(43)	$ —	$ 131
Interest rate swap agreements	$—	$300	$ —	$ 300	$(18)	$ —	$ 282
As of December 31, 2015							
Energy commodity derivative contracts(a)	$48	$589	$ 2	$ 639	$(12)	$ (37)	$ 590
Interest rate swap agreements	$—	$385	$ —	$ 385	$(8)	$ —	$ 377

	Balance sheet liability fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Collateral posted(c)	Net amount
As of December 31, 2016							
Energy commodity derivative contracts(a)	$(29)	$(82)	$—	$(111)	$43	$ 37	$ (31)
Interest rate swap agreements	$—	$(57)	$—	$(57)	$18	$ —	$ (39)
Cross-currency swap agreements	$—	$(31)	$—	$(31)	$—	$ —	$ (31)
As of December 31, 2015							
Energy commodity derivative contracts(a)	$(4)	$(10)	$(17)	$(31)	$12	$ —	$ (19)
Interest rate swap agreements	$—	$(25)	$—	$(25)	$8	$ —	$ (17)
Cross-currency swap agreements	$—	$(52)	$—	$(52)	$—	$ —	$ (52)

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(a) Level 1 consists primarily of NYMEX natural gas futures. Level 2 consists primarily of OTC WTI swaps and options and NGL swaps. Level 3 consists primarily of power derivative contracts.

(b) Cash margin deposits held by us associated with our energy commodity contract positions and OTC swap agreements and reported within "Other current liabilities" on our accompanying consolidated balance sheets.

(c) Cash margin deposits posted by us associated with our energy commodity contract positions and OTC swap agreements and reported within "Restricted Deposits" on our accompanying consolidated balance sheets.

The table below provides a summary of changes in the fair value of our Level 3 energy commodity derivative contracts (in millions):

Significant unobservable inputs (Level 3)

	Year Ended December 31,	
	2016	2015
Derivatives-net asset (liability)		

Beginning of period	$ (15)	$ (61)
Total gains or (losses) included in earnings	(9)	(13)
Settlements	24	59
End of period	$ —	$ (15)
The amount of total gains or (losses) for the period included in earnings attributable to the change in unrealized gains or (losses) relating to assets held at the reporting date	$ —	$ —

As of December 31, 2015, our Level 3 derivative assets and liabilities consisted primarily of power derivative contracts (which expired in April 2016), where a significant portion of fair value is calculated from underlying market data that is not readily observable. The derived values use industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management's best estimate of fair value and management does not expect materially different valuation results were we to use different input amounts within reasonable ranges.

Fair Value of Debt

The carrying value and estimated fair value of our outstanding debt balances is disclosed below (in millions):

	December 31, 2016		December 31, 2015	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Total debt	$40,050	$ 41,015	$43,227	$ 37,481

We used Level 2 input values to measure the estimated fair value of our outstanding debt balance as of both December 31, 2016 and 2015.

16. Reportable Segments

Our reportable business segments are:

- Natural Gas Pipelines—the ownership and operation of (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas and crude oil gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG facilities;

- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium for recovering crude oil from mature oil fields to increase production; (ii) ownership interests in and/or operation of oil fields and gas processing plants in West Texas; and (iii) the ownership and operation of a crude oil pipeline system in West Texas;

- Terminals—(i) the ownership and/or operation of liquids and bulk terminal facilities located throughout the U.S. and portions of Canada that transload and store refined petroleum products, crude oil, chemicals, and ethanol and bulk products, including coal, petroleum coke, fertilizer, steel and ores and (ii) Jones Act tankers;

- Products Pipelines—the ownership and operation of refined petroleum products, NGL and crude oil and condensate pipelines that primarily deliver, among other products, gasoline, diesel and jet fuel, propane, crude oil and condensate to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities; and

- Kinder Morgan Canada—the ownership and operation of the Trans Mountain pipeline system that transports crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia, Canada and the state of Washington, plus the Jet Fuel aviation turbine fuel pipeline that serves the Vancouver (Canada) International Airport.

We evaluate performance principally based on each segment's EBDA, which excludes general and administrative expenses, interest expense, net, and income tax expense. Our reportable segments are strategic business units that offer different products and services, and they are structured based on how our chief operating decision makers organize their operations for optimal performance and resource allocation. Each segment is managed separately because each segment involves different products and marketing strategies.

Segment results for the years ended December 31, 2015 and 2014 have been retrospectively adjusted to reflect the elimination of the Other segment as a reportable segment. The activities that previously comprised the Other segment are now presented within the Corporate non-segment activities in reconciling to the consolidated totals in the respective segment reporting tables. The Other segment had historically been comprised primarily of legacy operations of acquired businesses not associated with our ongoing operations. These business activities have since been sold or have otherwise ceased. In addition, the Other segment included certain company owned real estate assets which are primarily leased to our operating subsidiaries

as well as third party tenants. This activity is now reflected within Corporate activity. In addition, the portions of interest income and income tax expense previously allocated to our business segments is now included in "Interest expense, net" and "Income tax expense" for all periods presented in the following tables.
We consider each period's earnings before all non-cash DD&A expenses to be an important measure of business segment performance for our reporting segments. We account for intersegment sales at market prices, while we account for asset transfers at either market value or, in some instances, book value.

During 2016, 2015 and 2014, we did not have revenues from any single external customer that exceeded 10% of our consolidated revenues.

Financial information by segment follows (in millions):

	Year Ended December 31,		
	2016	2015	2014
Revenues			
Natural Gas Pipelines			
Revenues from external customers	$7,998	$8,704	$10,153
Intersegment revenues	7	21	15
CO_2	1,221	1,699	1,960
Terminals			
Revenues from external customers	1,921	1,878	1,717
Intersegment revenues	1	1	1
Products Pipelines			
Revenues from external customers	1,631	1,828	2,068
Intersegment revenues	18	3	—
Kinder Morgan Canada	253	260	291
Corporate and intersegment eliminations(a)	8	9	21
Total consolidated revenues	$13,058	$14,403	$16,226

	Year Ended December 31,		
	2016	2015	2014
Operating expenses(b)			
Natural Gas Pipelines	$4,393	$4,738	$6,241
CO_2	399	432	494
Terminals	768	836	746
Products Pipelines	573	772	1,258
Kinder Morgan Canada	87	87	106
Corporate and intersegment eliminations	2	26	8
Total consolidated operating expenses	$6,222	$6,891	$8,853

	Year Ended December 31,		
	2016	2015	2014
Other expense (income)(c)			
Natural Gas Pipelines	$ 199	$ 1,269	$ 5
CO_2	19	606	243
Terminals	99	190	29
Products Pipelines	76	2	(3)
Kinder Morgan Canada	—	(1)	—
Corporate	(7)	—	1
Total consolidated other expense (income)	$ 386	$ 2,066	$ 275

	Year Ended December 31,		
	2016	2015	2014
DD&A			
Natural Gas Pipelines	$ 1,041	$ 1,046	$ 897
CO_2	446	556	570
Terminals	435	433	337
Products Pipelines	221	206	166
Kinder Morgan Canada	44	46	51
Corporate	22	22	19
Total consolidated DD&A	$ 2,209	$ 2,309	$ 2,040

	Year Ended December 31,		
	2016	2015	2014
Earnings from equity investments and amortization of excess cost of equity investments, including loss on impairments			
Natural Gas Pipelines	$ (269)	$ 285	$ 279
CO_2	22	(5)	26
Terminals	19	17	18
Products Pipelines	56	36	37
Corporate	—	—	1
Total consolidated equity earnings	$ (172)	$ 333	$ 361

	Year Ended December 31,		
	2016	2015	2014
Other, net-income (expense)			
Natural Gas Pipelines	$ 19	$ 24	$ 24
Terminals	4	8	12
Products Pipelines	2	4	(1)
Kinder Morgan Canada	15	8	15
Corporate	4	(1)	30
Total consolidated other, net-income (expense)	$ 44	$ 43	$ 80

	Year Ended December 31,		
	2016	2015	2014
Segment EBDA(d)			
Natural Gas Pipelines	$3,211	$3,067	$4,264
CO_2	827	658	1,248
Terminals	1,078	878	973
Products Pipelines	1,067	1,106	856
Kinder Morgan Canada	181	182	200
Total segment EBDA	6,364	5,891	7,541
DD&A	(2,209)	(2,309)	(2,040)
Amortization of excess cost of equity investments	(59)	(51)	(45)
General and administrative expenses	(669)	(690)	(610)
Interest expense, net	(1,806)	(2,051)	(1,798)
Corporate(a)	17	(18)	43
Income tax expense	(917)	(564)	(648)
Total consolidated net income	$721	$208	$2,443

	Year Ended December 31,		
	2016	2015	2014
Capital expenditures			
Natural Gas Pipelines	$ 1,227	$ 1,642	$ 935
CO_2	276	725	792
Terminals	983	847	1,049
Products Pipelines	244	524	680
Kinder Morgan Canada	124	142	156
Corporate	28	16	5
Total consolidated capital expenditures	$ 2,882	$ 3,896	$ 3,617

	2016	2015
Investments at December 31		
Natural Gas Pipelines	$6,185	$5,080
Terminals	252	306
Products Pipelines	566	641
Kinder Morgan Canada	20	10
Corporate	4	3
Total consolidated investments	$7,027	$6,040

	2016	2015
Assets at December 31		
Natural Gas Pipelines	$50,428	$53,704
CO_2	4,065	4,706
Terminals	9,725	9,083
Products Pipelines	8,329	8,464
Kinder Morgan Canada	1,572	1,434
Corporate assets(e)	6,108	6,694
Assets held for sale	78	19
Total consolidated assets	$80,305	$84,104

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(a) Includes a management fee for services we perform as operator of an equity investee.

(b) Includes natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes.

(c) Includes loss on impairment of goodwill, loss on impairments and divestitures, net and other (income) expense, net.

(d) Includes revenues, earnings from equity investments, other, net, less operating expenses, and other (income) expense, net, loss on impairment of goodwill, and loss on impairments and divestitures, net and loss on impairments and divestitures of equity investments, net.

(e) Includes cash and cash equivalents, margin and restricted deposits, unallocable interest receivable, certain prepaid assets and deferred charges, including income tax related assets, risk management assets related to debt fair value adjustments, corporate headquarters in Houston, Texas and miscellaneous corporate assets (such as information technology, telecommunications equipment and legacy operations) not allocated to the reportable segments.

We do not attribute interest and debt expense to any of our reportable business segments.

Following is geographic information regarding the revenues and long-lived assets of our business segments (in millions):

	Year Ended December 31,		
	2016	2015	2014
Revenues from external customers			
U.S.	$12,459	$13,797	$15,605
Canada	483	479	437
Mexico	116	127	184
Total consolidated revenues from external customers	$13,058	$14,403	$16,226

	December 31,		
	2016	2015	2014
Long-term assets, excluding goodwill and other intangibles			
U.S.	$49,125	$51,679	$49,992
Canada	2,399	2,193	2,268
Mexico	82	67	81
Total consolidated long-lived assets	$51,606	$53,939	$52,341

17. Litigation, Environmental and Other Contingencies

We and our subsidiaries are parties to various legal, regulatory and other matters arising from the day-to-day operations of our businesses or certain predecessor operations that may result in claims against the Company. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves and insurance, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or dividends to our shareholders. We believe we have meritorious defenses to the matters to which we are a party and intend to vigorously defend the Company. When we determine a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such contingencies based on our best estimate using information available at that time. If the estimated loss is a range of potential outcomes and there is no better estimate within the range, we accrue the amount at the low end of the range. We disclose contingencies where an adverse outcome may be material, or in the judgment of management, we conclude the matter should otherwise be disclosed.

Federal Energy Regulatory Commission Proceedings

SFPP

The tariffs and rates charged by SFPP are subject to a number of ongoing proceedings at the FERC, including the complaints and protests of various shippers the most recent of which was filed in late 2015 with the FERC (docketed at OR16-6) challenging SFPP’s filed East Line rates. In general, these complaints and protests allege the rates and tariffs charged by SFPP are not just and reasonable under the Interstate Commerce Act (ICA). In some of these proceedings shippers have challenged the overall rate being charged by SFPP, and in others the shippers have challenged SFPP’s index-based rate increases. If the shippers prevail on their arguments or claims, they are entitled to seek reparations (which may reach back up to two years prior to the filing date of their complaints) or refunds of any excess rates paid, and SFPP may be required to reduce its rates going forward. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts. The issues involved in these proceedings include, among others, whether indexed rate increases are justified, and the appropriate level of return and income tax allowance SFPP may include in its rates. On March 22, 2016, the D.C. Circuit issued a decision in United Airlines, Inc. v. FERC remanding to FERC for further consideration of two issues: (1) the appropriate data to be used to determine the return on equity for SFPP in the underlying docket, and (2) the just and reasonable return to be provided to a tax pass-through entity that includes an income tax allowance in its underlying cost of service. With respect to the various SFPP related complaints and protest proceedings at the FERC, we estimate that the shippers are seeking approximately $40 million in annual rate reductions and approximately $190 million in refunds. Management believes SFPP has meritorious arguments supporting SFPP’s rates and intends to vigorously defend SFPP against these complaints and protests. However, to the extent the shippers are successful in one or more of the complaints or protest proceedings, SFPP estimates that applying the principles of FERC precedent, as applicable, to pending SFPP cases would result in rate reductions and refunds substantially lower than those sought by the shippers.

EPNG

The tariffs and rates charged by EPNG are subject to two ongoing FERC proceedings (the “2008 rate case” and the “2010 rate case”). With respect to the 2008 rate case, the FERC issued its decision (Opinion 517-A) in July 2015. The FERC generally upheld its prior determinations, ordered refunds to be paid within 60 days, and stated that it will apply its findings in Opinion 517-A to the same issues in the 2010 rate case. EPNG has sought federal appellate review of Opinion 517-A and oral argument is scheduled for February 15, 2017. With respect to the 2010 rate case, the FERC issued its decision (Opinion 528-A) on February 18, 2016. The FERC generally upheld its prior determinations, affirmed prior findings of an Administrative Law Judge that certain shippers qualify for lower rates, and required EPNG to file revised pro forma recalculated rates consistent with the terms of Opinions 517-A and 528-A. EPNG and two intervenors sought rehearing of certain aspects of the decision, and the judicial review sought by certain intervenors has been delayed until the FERC issues an order on rehearing. All refund obligations related to the 2008 rate case were satisfied during calendar year 2015. With respect to the 2010 rate case, EPNG believes it has an appropriate reserve related to the findings in Opinions 517-A and 528-A.

NGPL and WIC

On January 19, 2017, NGPL and WIC were notified by the FERC of rate proceedings against them pursuant to section 5 of the Natural Gas Act (the “Orders”). Each respective proceeding will set the matter for hearing and determine whether NGPL’s and WIC’s current rates remain just and reasonable. A proceeding under section 5 of the Natural Gas Act is prospective in nature such that a change in rates charged to customers, if any, would likely only occur after the FERC has issued a final order. Unless a settlement is reached sooner, an initial Administrative Law Judge decision is anticipated in late February, 2018, with a final FERC decision anticipated by the third quarter, 2018. We do not believe that the ultimate resolution of these proceedings will have a material adverse impact on our results of operations or cash flows from operations.

Other Commercial Matters

Union Pacific Railroad Company Easements & Related Litigation

SFPP and Union Pacific Railroad Company (UPRR) are engaged in a proceeding to determine the extent, if any, to which the rent payable by SFPP for the use of pipeline easements on rights-of-way held by UPRR should be adjusted pursuant to existing contractual arrangements for the ten-year period beginning January 1, 2004 (Union Pacific Railroad Company v. Santa Fe Pacific Pipelines, Inc., SFPP, L.P., Kinder Morgan Operating L.P. “D”, Kinder Morgan G.P., Inc., et al., Superior Court of the State of California for the County of Los Angeles, filed July 28, 2004). In September 2011, the trial judge determined that the annual rent payable as of January 1, 2004 was $14 million, subject to annual consumer price index increases. SFPP appealed the judgment.

By notice dated October 25, 2013, UPRR demanded the payment of $22.3 million in rent for the first year of the next ten-year period beginning January 1, 2014, which SFPP rejected.

On November 5, 2014, the Court of Appeals issued an opinion which reversed the judgment, including the award of prejudgment interest, and remanded the matter to the trial court for a determination of UPRR’s property interest in its right-of-way, including whether UPRR has sufficient interest to grant SFPP’s easements. UPRR filed a petition for review to the California Supreme Court which was denied. The trial court has not set a date for the retrial.

After the above-referenced decision by the California Court of Appeals which held that UPRR does not own the subsurface rights to grant certain easements and may not be able to collect rent from those easements, a purported class action lawsuit was filed in 2015 in the U.S. District Court for the Southern District of California by private landowners in California who claim to be the lawful owners of subsurface real property allegedly used or occupied by UPRR or SFPP. Substantially similar follow-on lawsuits were filed and are pending in federal courts by landowners in Nevada, Arizona and New Mexico. These suits, which are brought purportedly as class actions on behalf of all landowners who own land in fee adjacent to and underlying the railroad easement under which the SFPP pipeline is located in those respective states, assert claims against UPRR, SFPP, KMGP, and Kinder Morgan Operating L.P. “D” for declaratory judgment, trespass, ejectment, quiet title, unjust enrichment, accounting, and alleged unlawful business acts and practices arising from defendants’ alleged improper use or occupation of subsurface real property. SFPP views these cases as primarily a dispute between UPRR and the plaintiffs. UPRR purported to grant SFPP a network of subsurface pipeline easements along UPRR’s railroad right-of-way. SFPP relied on the validity of those easements and paid rent to UPRR for the value of those easements. We believe we have recorded a right-of-way liability sufficient to cover our potential obligation, if any, for back rent.

SFPP and UPRR have engaged in multiple disputes over the circumstances under which SFPP must pay for relocations of its pipeline within the UPRR right-of-way and the safety standards that govern relocations. In 2006, following a bench trial regarding the circumstances under which SFPP must pay for relocations, the judge determined that SFPP must pay for any relocations resulting from any legitimate business purpose of the UPRR. The decision was affirmed on appeal. In addition, UPRR contends that SFPP must comply with the more expensive American Railway Engineering and Maintenance-of-Way Association (AREMA) standards in determining when relocations are necessary and in completing relocations. Each party has sought declaratory relief with respect to its positions regarding the application of these standards with respect to relocations. In 2011, a jury verdict was reached that SFPP was obligated to comply with AREMA standards in connection with a railroad project in Beaumont Hills, California. In 2014, the trial court entered judgment against SFPP, consistent with the jury’s verdict. On June 29, 2015, the parties entered into a confidential settlement of all of the claims relating to the project in Beaumont Hills and the case was dismissed.

Since SFPP does not know UPRR’s plans for projects or other activities that would cause pipeline relocations, it is difficult to quantify the effects of the outcome of these cases on SFPP. Even if SFPP is successful in advancing its positions, significant relocations for which SFPP must nonetheless bear the cost (i.e., for railroad purposes, with the standards in the federal Pipeline Safety Act applying) could have an adverse effect on our financial position, results of operations, cash flows, and our dividends to our shareholders. These effects could be even greater in the event SFPP is unsuccessful in one or more of these lawsuits.

Gulf LNG Facility Arbitration

On March 1, 2016, Gulf LNG Energy, LLC and Gulf LNG Pipeline, LLC (GLNG) received a Notice of Disagreement and Disputed Statements and a Notice of Arbitration from Eni USA Gas Marketing LLC (Eni USA), one of two companies that entered into a terminal use agreement for capacity of the Gulf LNG Facility in Mississippi for an initial term that is not scheduled to expire until the year 2031. Eni USA is an indirect subsidiary of Eni S.p.A., a multi-national integrated energy company headquartered in Milan, Italy. Pursuant to its Notice of Arbitration, Eni USA seeks declaratory and monetary relief based upon its assertion that (i) the terminal use agreement should be terminated because changes in the U.S. natural gas market since the execution of the agreement in December 2007 have “frustrated the essential purpose” of the agreement and (ii) activities allegedly undertaken by affiliates of Gulf LNG Holdings Group LLC “in connection with a plan to convert the LNG Facility into a liquefaction/export facility have given rise to a contractual right on the part of Eni USA to terminate” the agreement. As set forth in the terminal use agreement, disputes are meant to be resolved by final and binding arbitration. A three-member arbitration panel conducted an arbitration hearing in January 2017. We expect the arbitration panel will issue its decision within approximately six months. Eni USA has indicated that it will continue to pay the amounts claimed to be due pending resolution of the dispute. The successful assertion by Eni USA of its claim to terminate or amend its payment obligations under the agreement prior to the expiration of its initial term could have an adverse effect on the business, financial position, results of operations, or cash flows of GLNG and distributions to KMI, a 50% shareholder of GLNG. We view the demand for arbitration to be without merit, and we intend to contest it vigorously.

Plains Gas Solutions, LLC v. Tennessee Gas Pipeline Company, L.L.C. et al.

On October 16, 2013, Plains Gas Solutions, LLC (Plains) filed a petition in the 151st Judicial District Court for Harris County, Texas (Case No. 62528) against TGP, Kinetica Partners, LLC and two other Kinetica entities. The suit arose from the sale by TGP of the Cameron System in Louisiana to Kinetica Partners, LLC on September 1, 2013. Plains alleged that defendants breached a straddle agreement requiring that gas on the Cameron System be committed to Plains' Grand Chenier gas-processing facility, that requisite daily volume reports were not provided, that TGP improperly assigned its obligations under the straddle agreement to Kinetica, and that defendants interfered with Plains' contracts with producers. The petition alleged damages of at least $100 million. Under the Amended and Restated Purchase and Sale Agreement with Kinetica, Kinetica is obligated to defend and indemnify TGP in connection with the gas commitment and reporting claims. After agreeing initially to defend and indemnify TGP against such claims, Kinetica withdrew its defense, disputed its indemnity obligation, and settled with Plains. On January 20, 2017, Plains and TGP agreed to release and dismiss their claims and causes of action in the lawsuit with prejudice.

Brinckerhoff v. El Paso Pipeline GP Company, LLC., et al.

In December 2011 (Brinckerhoff I), March 2012, (Brinckerhoff II), May 2013 (Brinckerhoff III) and June 2014 (Brinckerhoff IV), derivative lawsuits were filed in Delaware Chancery Court against El Paso Corporation, El Paso Pipeline GP Company, L.L.C., the general partner of EPB, and the directors of the general partner at the time of the relevant transactions. EPB was named in these lawsuits as a "Nominal Defendant." The lawsuits arise from the March 2010, November 2010, May 2012 and June 2011 drop-down transactions involving EPB's purchase of SLNG, Elba Express, CPG and interests in SNG and CIG. The lawsuits allege various conflicts of interest and that the consideration paid by EPB was excessive. Brinckerhoff I and II were consolidated into one proceeding. Motions to dismiss were filed in Brinckerhoff III and Brinckerhoff IV, and such motions remain pending. On June 12, 2014, defendants' motion for summary judgment was granted in Brinckerhoff I, dismissing the case in its entirety. Defendants' motion for summary judgment in Brinckerhoff II was granted in part, dismissing certain claims and allowing the matter to go to trial in late 2014 on the remaining claims. On April 20, 2015, the Court issued a post-trial memorandum opinion (Memorandum Opinion) in Brinckerhoff II entering judgment in favor of all of the defendants other than the general partner of EPB, but finding the general partner liable for breach of contract in connection with EPB's purchase of 49% interests in Elba and SLNG and a 15% interest in SNG in a $1.13 billion drop-down transaction that closed on November 19, 2010 (Fall Dropdown), prior to our acquisition of El Paso Corporation in 2012. In its Memorandum Opinion, the Court determined that EPB suffered damages of $171 million from the Fall Dropdown, which the Court determined to be the amount that EPB overpaid for Elba. We believe the claim is derivative in nature and was extinguished by our acquisition on November 26, 2014, pursuant to a merger agreement, of all of the outstanding common units of EPB that we did not already own. On December 2, 2015, the Court denied our motion to dismiss the remaining claims in Brinckerhoff II based upon our acquisition of all of the outstanding common units of EPB, and held that damages should be calculated by considering the unaffiliated unitholders' ownership percentage as of the effective date of the merger. Based on this ruling, the Court entered judgment on February 4, 2016 in the amount of $100.2 million plus interest at the legal rate for the period from November 15, 2010 until the date of payment, if any payment is ultimately required. We filed an appeal to the Delaware Supreme Court and Brinckerhoff filed a cross-appeal challenging the dismissal of Brinckerhoff I. On December 20, 2016, the Delaware Supreme Court issued an opinion reversing the trial court's December 2, 2015 decision, finding that the claims were derivative in nature and that Brinckerhoff lost standing to continue both the appeal and cross-appeal when the merger closed. Because its holding terminates the litigation, the Supreme Court did not reach the other issues raised by the parties. On January 5, 2017, the Supreme Court issued a mandate to the trial court reversing the February 4, 2016 judgment in its entirety. On January 30, 2017, the trial court dismissed the case. We continue to believe the transactions at issue were appropriate and in the best interests of EPB. We believe the remaining lawsuits (Brinckerhoff III and IV) should be dismissed on the same grounds, among others, as Brinckerhoff I and II and we intend to continue to defend such lawsuits vigorously.

Price Reporting Litigation

Beginning in 2003, several lawsuits were filed by purchasers of natural gas against El Paso Corporation, El Paso Marketing L.P. and numerous other energy companies based on a claim under state antitrust law that such defendants conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. Several of the cases have been settled or dismissed. The remaining cases, which are pending in Nevada federal court, were dismissed, but the dismissal was reversed by the 9th Circuit Court of Appeals. The U.S. Supreme Court affirmed the 9th

Circuit Court of Appeals in a decision dated April 21, 2015, and the cases were then remanded to the Nevada federal court for further consideration and trial, if necessary, of numerous remaining issues. On May 24, 2016, the Court granted a motion for summary judgment dismissing a lawsuit brought by an industrial consumer in Kansas in which approximately $500 million in damages has been alleged. That ruling has been appealed to the 9th Circuit Court of Appeals. Tentative settlements have been reached in class actions originally filed in Kansas and Missouri, which settlements are subject to court approval. In the remaining case, a Wisconsin class action, approximately $300 million in damages have been alleged against all defendants. There remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, which may be allocated to us in the remaining lawsuits and therefore, our legal exposure, if any, and costs are not currently determinable.

Kinder Morgan, Inc. Corporate Reorganization Litigation

Certain unitholders of KMP and EPB filed five putative class action lawsuits in the Court of Chancery of the State of Delaware in connection with our November 26, 2014 acquisition, pursuant to three separate merger agreements, of all of the outstanding common units of KMP and EPB and all of the outstanding shares of KMR that we did not already own. The lawsuits were consolidated under the caption In re Kinder Morgan, Inc. Corporate Reorganization Litigation (Consolidated Case No. 10093-VCL). On December 12, 2014, the plaintiffs filed a Verified Second Consolidated Amended Class Action Complaint, which purported to assert claims on behalf of both the former EPB unitholders and the former KMP unitholders. The EPB plaintiff alleged that (i) El Paso Pipeline GP Company, L.L.C. (EPGP), the general partner of EPB, and the directors of EPGP breached duties under the EPB partnership agreement, including the implied covenant of good faith and fair dealing, by entering into the EPB Transaction; (ii) EPB, E Merger Sub LLC, KMI and individual defendants aided and abetted such breaches; and (iii) EPB, E Merger Sub LLC, KMI, and individual defendants tortiously interfered with the EPB partnership agreement by causing EPGP to breach its duties under the EPB partnership agreement.

The KMP plaintiffs alleged that (i) KMR, KMGP, and individual defendants breached duties under the KMP partnership agreement, including the implied duty of good faith and fair dealing, by entering into the KMP Transaction and by failing to adequately disclose material facts related to the transaction; (ii) KMI aided and abetted such breach; and (iii) KMI, KMP, KMR, P Merger Sub LLC, and individual defendants tortiously interfered with the rights of the plaintiffs and the putative class under the KMP partnership agreement by causing KMGP to breach its duties under the KMP partnership agreement. The complaint sought declaratory relief that the transactions were unlawful and unenforceable, reformation, rescission, rescissory or compensatory damages, interest, and attorneys' and experts' fees and costs. On December 30, 2014, the defendants moved to dismiss the complaint. On April 2, 2015, the EPB plaintiff and the defendants submitted a stipulation and proposed order of dismissal, agreeing to dismiss all claims brought by the EPB plaintiff with prejudice as to the EPB lead plaintiff and without prejudice to all other members of the putative EPB class. The Court entered such order on April 2, 2015.

On August 24, 2015, the Court issued an order granting the defendants' motion to dismiss the remaining counts of the complaint for failure to state a claim. On September 21, 2015, plaintiffs filed a notice of appeal to the Supreme Court of the State of Delaware, captioned Haynes Family Trust et al. v. Kinder Morgan G.P., Inc. et al. (Case No. 515). On March 10, 2016, the Delaware Supreme Court affirmed the dismissal of all claims on appeal and this matter is now concluded.

Pipeline Integrity and Releases

From time to time, despite our best efforts, our pipelines experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, and damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages caused by an alleged failure to properly mark the locations of our pipelines and/or to properly maintain our pipelines. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

General

As of December 31, 2016 and 2015, our total reserve for legal matters was $407 million and $463 million, respectively. The reserve primarily relates to various claims from regulatory proceedings arising in our products and natural gas pipeline segments and certain corporate matters.

Environmental Matters

We and our subsidiaries are subject to environmental cleanup and enforcement actions from time to time. In particular, CERCLA generally imposes joint and several liability for cleanup and enforcement costs on current and predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct, subject to the right of a liable party to establish a “reasonable basis” for apportionment of costs. Our operations are also subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in pipeline, terminal and CO_2 field and oil field operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies under the terms of authority of those laws, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

We are currently involved in several governmental proceedings involving alleged violations of environmental and safety regulations, including alleged violations of the Risk Management Program and leak detection and repair requirements of the Clean Air Act. As we receive notices of non-compliance, we attempt to negotiate and settle such matters where appropriate. These alleged violations may result in fines and penalties, but we do not believe any such fines and penalties, individually or in the aggregate, will be material. We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under administrative orders or related state remediation programs. We have established a reserve to address the costs associated with the cleanup.

In addition, we are involved with and have been identified as a potentially responsible party in several federal and state superfund sites. Environmental reserves have been established for those sites where our contribution is probable and reasonably estimable. In addition, we are from time to time involved in civil proceedings relating to damages alleged to have occurred as a result of accidental leaks or spills of refined petroleum products, NGL, natural gas and CO_2.

Portland Harbor Superfund Site, Willamette River, Portland, Oregon

In December 2000, the EPA issued General Notice letters to potentially responsible parties including GATX Terminals Corporation (n/k/a KMLT). At that time, GATX owned two liquids terminals along the lower reach of the Willamette River, an industrialized area known as Portland Harbor. Portland Harbor is listed on the National Priorities List and is designated as a Superfund Site under CERCLA. A group of potentially responsible parties formed what is known as the Lower Willamette Group (LWG), of which KMLT is a non-voting member and pays a minimal fee to be part of the group. The LWG agreed to conduct the remedial investigation and feasibility study (RI/FS) leading to the proposed remedy for cleanup of the Portland Harbor site. After a dispute with the EPA concerning certain provision of the FS, the parties agreed that the EPA would complete the FS and that the LWG may dispute the FS within 14 days of the publication of the proposed remedy for cleanup. EPA issued the FS and the Proposed Plan on June 8, 2016. The EPA’s Proposed Plan included a combination of dredging, capping, and enhanced natural recovery. Comments on the FS and the Proposed Plan were submitted by the LWG and on our own behalf on September 7, 2016. On January 6, 2017, the EPA issued its Record of Decision (ROD) for the final cleanup plan. The final remedy is more stringent than the remedy proposed in the EPA’s Proposed Plan. The estimated cost has increased from approximately $750 million to approximately $1.1 billion and active cleanup is now expected to take as long as 13 years to complete. KMLT and 90 other parties are involved in a non-judicial allocation process to determine each party’s respective share of the cleanup costs. We are participating in the allocation process on behalf of KMLT and KMBT in connection with their current or former ownership or operation of four facilities located in Portland Harbor. Our share of responsibility for Portland Harbor Superfund Site costs will not be determined until the ongoing non-judicial allocation process is concluded in several years or a lawsuit is filed that results in a judicial decision allocating responsibility. Until the allocation process is completed, we are unable to reasonably estimate the extent of our liability for the costs related to the design of the proposed remedy and cleanup of the site.

Roosevelt Irrigation District v. Kinder Morgan G.P., Inc., Kinder Morgan Energy Partners, L.P. , U.S. District Court, Arizona

The Roosevelt Irrigation District sued KMGP, KMEP and others under CERCLA for alleged contamination of the water purveyor's wells. The First Amended Complaint sought $175 million in damages from approximately 70 defendants. On August 6, 2013 plaintiffs filed their Second Amended Complaint seeking monetary damages in unspecified amounts and reducing the number of defendants to 26 including KMEP and SFPP. The claims now presented against KMEP and SFPP are related to alleged releases from a specific parcel within the SFPP Phoenix Terminal and the alleged impact of such releases on water wells owned by the plaintiffs and located in the vicinity of the Terminal. We have filed an answer, general denial, and affirmative defenses in response to the Second Amended Complaint and fact discovery is proceeding.

Mission Valley Terminal Lawsuit

In August 2007, the City of San Diego, on its own behalf and purporting to act on behalf of the People of the State of California, filed a lawsuit against us and several affiliates seeking injunctive relief and unspecified damages allegedly resulting from hydrocarbon and methyl tertiary butyl ether (MTBE) impacted soils and groundwater beneath the City's stadium property in San Diego arising from historic operations at the Mission Valley terminal facility. The case was filed in the Superior Court of California, San Diego County and was removed in 2007 to the U.S. District Court, Southern District of California (Case No. 07CV1883WCAB). The City disclosed in discovery that it was seeking approximately $170 million in damages for alleged lost value/lost profit from the redevelopment of the City's property and alleged lost use of the water resources underlying the property. Later, in 2010, the City amended its initial disclosures to add claims for restoration of the site as well as a number of other claims that increased its claim for damages to approximately $365 million.

On November 29, 2012, the Court issued a Notice of Tentative Rulings on the parties' summary adjudication motions. The Court tentatively granted our partial motions for summary judgment on the City's claims for water and real estate damages and the State's claims for violations of California Business and Professions Code § 17200, tentatively denied the City's motion for summary judgment on its claims of liability for nuisance and trespass, and tentatively granted our cross motion for summary judgment on such claims. On January 25, 2013, the Court rendered judgment in favor of all defendants on all claims asserted by the City.

On February 20, 2013, the City of San Diego filed a notice of appeal to the U.S. Court of Appeals for the Ninth Circuit. On May 21, 2015, the Court of Appeals issued a memorandum decision which affirmed the District Court's summary judgment in our favor with respect to the City's claim under California Safe Drinking Water and Toxic Enforcement Act, but reversed both the District Court's summary judgment decision in our favor on the City's remaining claims and the District Court's decision to exclude the City's expert testimony. The Court of Appeals issued a mandate returning the case to the U.S. District Court.

On June 17, 2016, the parties entered into a settlement resolving all claims related to the historical contamination at the City's stadium property. The settlement provides for a $20 million payment to the City, a waiver and release by the City of all claims which were asserted or could have been asserted in the litigation, and an agreement by defendants to indemnify the City for additional, incremental costs, if any, incurred by the City in the redevelopment of the stadium property or the development of groundwater beneath the stadium property, that would not have been incurred but for the historical releases from the Mission Valley Terminal. By Order dated June 17, 2016, the District Court granted dismissal of the litigation.

This site remains under the regulatory oversight and order of the California Regional Water Quality Control Board (RWQCB). SFPP completed the soil and groundwater remediation at the City of San Diego's stadium property site and conducted quarterly sampling and monitoring through 2015 as part of the compliance evaluation required by the RWQCB. The RWQCB issued a notice of no further action with respect to the stadium property site on May 4, 2016. SFPP's remediation effort is now focused on its adjacent Mission Valley Terminal site.

Uranium Mines in Vicinity of Cameron, Arizona

In the 1950s and 1960s, Rare Metals Inc., a historical subsidiary of EPNG, mined approximately twenty uranium mines in the vicinity of Cameron, Arizona, many of which are located on the Navajo Indian Reservation. The mining activities were in response to numerous incentives provided to industry by the U.S. to locate and produce domestic sources of uranium to support the Cold War-era nuclear weapons program. In May 2012, EPNG received a general notice letter from the EPA notifying EPNG of the EPA's investigation of certain sites and its determination that the EPA considers EPNG to be a potentially responsible party within the meaning of CERCLA. In August 2013, EPNG and the EPA entered into an Administrative Order on Consent and Scope of Work pursuant to which EPNG is conducting a radiological assessment of the surface of the mines. On September 3, 2014, EPNG filed a complaint in the U.S. District Court for the District of Arizona (Case No. 3:14-08165-DGC) seeking cost recovery and contribution from the applicable federal government agencies toward the cost of environmental activities associated with the mines, given the pervasive control of such federal agencies over all aspects of the nuclear weapons program.

Defendants filed an answer and counterclaims seeking contribution and recovery of response costs allegedly incurred by the federal agencies in investigating uranium impacts on the Navajo Reservation. The counterclaim of defendant EPA has been settled, and no viable claims for reimbursement by the other defendants are known to exist.

Lower Passaic River Study Area of the Diamond Alkali Superfund Site, Essex, Hudson, Bergen and Passaic Counties, New Jersey

EPEC Polymers, Inc. (EPEC Polymers) and EPEC Oil Company Liquidating Trust (EPEC Oil Trust), former El Paso Corporation entities now owned by KMI, are involved in an administrative action under CERCLA known as the Lower Passaic River Study Area Superfund Site (Site) concerning the lower 17-mile stretch of the Passaic River. It has been alleged that EPEC Polymers and EPEC Oil Trust may be potentially responsible parties (PRPs) under CERCLA based on prior ownership and/or operation of properties located along the relevant section of the Passaic River. EPEC Polymers and EPEC Oil Trust entered into two Administrative Orders on Consent (AOCs) which obligate them to investigate and characterize contamination at the Site. They are also part of a joint defense group (JDG) of approximately 70 cooperating parties which have entered into AOCs and are directing and funding the work required by the EPA. Under the first AOC, draft remedial investigation and feasibility studies (RI/FS) of the Site were submitted to the EPA in 2015, and comments from the EPA remain pending. Under the second AOC, the JDG members conducted a CERCLA removal action at the Passaic River Mile 10.9, and the group is currently conducting EPA-directed post-remedy monitoring in the removal area. We have established a reserve for the anticipated cost of compliance with the AOCs.

On April 11, 2014, the EPA announced the issuance of its Focused Feasibility Study (FFS) for the lower eight miles of the Passaic River Study Area, and its proposed plan for remedial alternatives to address the dioxin sediment contamination from the mouth of Newark Bay to River Mile 8.3. The EPA estimates the cost for the alternatives will range from $365 million to $3.2 billion. The EPA's preferred alternative would involve dredging the river bank-to-bank and installing an engineered cap at an estimated cost of $1.7 billion. On March 4, 2016, the EPA issued its ROD for the lower 8.3 miles of the Passaic River Study area. The final cleanup plan in the ROD is substantially similar to the EPA's preferred alternative announced on April 11, 2014. On October 5, 2016, the EPA entered into an AOC with one member of the PRP group requiring such member to spend $165 million to perform engineering and design work necessary to begin the cleanup of the lower 8.3 miles of the Passaic River. The design work is expected to take four years to complete and the cleanup is expected to take six years to complete.

In addition to the AOC with one member of the PRP group described above, the EPA has notified over 80 other PRPs, including EPEC Polymers and EPEC Oil Trust (the Notice), that the EPA intends to pursue additional agreements with other "major PRPs" and initiate negotiations over cash buyouts with parties whom the EPA does not consider "major PRPs." The Notice creates significant uncertainty as to the implementation and associated costs of the remedy set forth in the FFS and ROD, and provides no guidance as to the EPA's definition of a "major PRP" or the potential amount or range of cash buyouts. There is also uncertainty as to the impact of the RI/FS that the CPG is currently preparing for portions of the Site. The draft RI/FS was submitted by the CPG earlier in 2015 and proposes a different remedy than the FFS announced by the EPA. Therefore, the scope of potential EPA claims for the lower eight miles of the Passaic River is not reasonably estimable at this time.

Southeast Louisiana Flood Protection Litigation

On July 24, 2013, the Board of Commissioners of the Southeast Louisiana Flood Protection Authority - East (SLFPA) filed a petition for damages and injunctive relief in state district court for Orleans Parish, Louisiana (Case No. 13-6911) against TGP, SNG and approximately 100 other energy companies, alleging that defendants' drilling, dredging, pipeline and industrial operations since the 1930's have caused direct land loss and increased erosion and submergence resulting in alleged increased storm surge risk, increased flood protection costs and unspecified damages to the plaintiff. The SLFPA asserts claims for negligence, strict liability, public nuisance, private nuisance, and breach of contract. Among other relief, the petition seeks unspecified monetary damages, attorney fees, interest, and injunctive relief in the form of abatement and restoration of the alleged coastal land loss including but not limited to backfilling and re-vegetation of canals, wetlands and reef creation, land bridge construction, hydrologic restoration, shoreline protection, structural protection, and bank stabilization. On August 13, 2013, the suit was removed to the U.S. District Court for the Eastern District of Louisiana. On February 13, 2015, the Court granted defendants' motion to dismiss the suit for failure to state a claim, and issued an order dismissing the SLFPA's claims with prejudice. The SLFPA filed a notice of appeal on February 20, 2015. The U.S. Court of Appeals for the Fifth Circuit heard oral argument on February 29, 2016 and we await the Court's decision.

Plaquemines Parish Louisiana Coastal Zone Litigation

On November 8, 2013, the Parish of Plaquemines, Louisiana filed a petition for damages in the state district court for Plaquemines Parish, Louisiana (Docket No. 60-999) against TGP and 17 other energy companies, alleging that defendants' oil and gas exploration, production and transportation operations in the Bastian Bay, Buras, Empire and Fort Jackson oil and gas fields of Plaquemines Parish caused substantial damage to the coastal waters and nearby lands (Coastal Zone) within the Parish, including the erosion of marshes and the discharge of oil waste and other pollutants which detrimentally affected the quality of state waters and plant and animal life, in violation of the State and Local Coastal Resources Management Act of 1978 (Coastal Zone Management Act). As a result of such alleged violations of the Coastal Zone Management Act, Plaquemines Parish seeks, among other relief, unspecified monetary relief, attorney fees, interest, and payment of costs necessary to restore the allegedly affected Coastal Zone to its original condition, including costs to clear, vegetate and detoxify the Coastal Zone. In connection with this suit, TGP has made two tenders for defense and indemnity: (1) to Anadarko, as successor to the entity that purchased TGP's oil and gas assets in Bastian Bay, and (2) to Kinetica, which purchased TGP's pipeline assets in Bastian Bay in 2013. Anadarko has accepted TGP's tender (limited to oil and gas assets), and Kinetica rejected TGP's tender. TGP responded to Kinetica by reasserting TGP's demand for defense and indemnity and reserving its rights. On November 12, 2015, the Plaquemines Parish Council adopted a resolution directing its legal counsel in all its Coastal Zone cases to take all actions necessary to cause the dismissal of all such cases. On April 14, 2016, following interventions in the suit by the Louisiana Department of Natural Resources and Attorney General, the Parish Council passed a resolution rescinding its November 12, 2015 resolution that had directed its counsel to dismiss the suit. We intend to continue to vigorously defend the suit.

Vermilion Parish Louisiana Coastal Zone Litigation

On July 28, 2016, the District Attorney for the 15th Judicial District of Louisiana, purporting to act on behalf of Vermilion Parish and the State of Louisiana, filed suit in the state district court for Vermilion Parish, Louisiana against TGP and 52 other energy companies, alleging that the defendants' oil and gas and transportation operations associated with the development of several fields in Vermilion Parish (Operational Areas) were conducted in violation of the Coastal Zone Management Act. The suit alleges such operations caused substantial damage to the coastal waters and nearby lands (Coastal Zone) of Vermilion Parish, resulting in the release of pollutants and contaminants into the environment, improper discharge of oil field wastes, the improper use of waste pits and failure to close such pits, and the dredging of canals, which resulted in degradation of the Operational Areas, including erosion of marshes and degradation of terrestrial and aquatic life therein. As a result of such alleged violations of the Coastal Zone Management Act, the suit seeks a judgment against the defendants awarding all appropriate damages, the payment of costs to clear, revegetate, detoxify and otherwise restore the Vermilion Parish Coastal Zone, actual restoration of the affected Coastal Zone to its original condition, and reasonable costs and attorney fees. On September 2, 2016, the case was removed to the United States District Court for the Western District of Louisiana. On September 20, 2016, the plaintiffs filed a motion to remand the case back to the state district court. A hearing on this motion has been continued until a decision has been reached by the U.S. Court of Appeals for the Fifth Circuit in the Southeast Louisiana Flood Protection Litigation discussed above.

Vintage Assets, Inc. Coastal Erosion Litigation

On December 18, 2015, Vintage Assets, Inc. filed a petition in the 25th Judicial District Court for Plaquemines Parish, Louisiana alleging that its 5,000 acre property is composed of coastal wetlands, and that SNG, TGP, and certain other defendants failed to maintain pipeline canals and banks, causing widening of the canals, land loss, and damage to the ecology and hydrology of the marsh, in breach of right of way agreements, prudent operating practices, and Louisiana law. The suit also claims that defendants' alleged failure to maintain pipeline canals and banks constitutes negligence and has resulted in encroachment of the canals, constituting trespass. The suit seeks in excess of $80 million in money damages, including recovery of litigation costs, damages for trespass, and money damages associated with an alleged loss of natural resources and projected reconstruction cost of replacing or restoring wetlands. The suit was removed to the U.S. District Court for the Eastern District of Louisiana. The SNG assets at issue were sold to Highpoint Gas Transmission, LLC in 2011, which was subsequently purchased by American Midstream Partners, LP. In response to SNG's demand for defense and indemnity, American Midstream Partners agreed to pay 50% of joint defense costs and expenses, with a percentage of indemnity to be determined upon final resolution of the suit. On October 20, 2016, plaintiffs filed an amended complaint naming Highpoint Gas Transmission, LLC as an additional defendant. A non-jury trial is scheduled to begin on September 11, 2017 and we intend to vigorously defend the suit.

General

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note, and other matters to which we and our subsidiaries are a party, will not have a material adverse effect on our business, financial position, results of operations or cash flows. As of December 31, 2016 and 2015, we have accrued a total reserve for environmental liabilities in the amount of $302 million and $284 million, respectively. In addition, as of December 31, 2016 and 2015, we have recorded a receivable of $13 million for expected cost recoveries that have been deemed probable.

18. Recent Accounting Pronouncements

Accounting Standards Updates

Topic 606

On May 28, 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers” followed by a series of related accounting standard updates (collectively referred to as “Topic 606”). Topic 606 is designed to create greater revenue recognition and disclosure comparability in financial statements. The provisions of Topic 606 include a five-step process by which an entity will determine revenue recognition, depicting the transfer of goods or services to customers in amounts reflecting the payment to which an entity expects to be entitled in exchange for those goods or services. Topic 606 requires certain disclosures about contracts with customers and provides more comprehensive guidance for transactions such as service revenue, contract modifications, and multiple-element arrangements.

We are in the process of comparing our current revenue recognition policies to the requirements of Topic 606 for each of our revenue categories. While we have not identified any material differences in the amount and timing of revenue recognition for the categories we have reviewed to date, our evaluation is not complete and we have not concluded on the overall impacts of adopting Topic 606. Topic 606 will require that our revenue recognition policy disclosure include further detail regarding our performance obligations as to the nature, amount, timing, and estimates of revenue and cash flows generated from our contracts with customers. Topic 606 will also require disclosure of significant changes in contract asset and contract liability balances period to period and the amount of the transaction price allocated to performance obligations that are unsatisfied (or partially unsatisfied) as of the end of the reporting period, as applicable. We will adopt Topic 606 effective January 1, 2018. Topic 606 provides for adoption either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. We plan to make a determination as to our method of adoption once we more fully complete our evaluation of the impacts of the standard on our revenue recognition and we are better able to evaluate the cost-benefit of each method.

ASU No. 2014-15

On August 27, 2014, the FASB issued ASU No. 2014-15, “Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern.” This ASU provides guidance about management’s responsibility to evaluate whether there is substantial doubt about an entity’s ability to continue as a going concern and to provide related footnote disclosures if management concludes that substantial doubt exists or that its plans alleviate substantial doubt that was raised. We adopted ASU 2014-15 for the year ended December 31, 2016 with no impact to our financial statements.

ASU No. 2015-02

On February 18, 2015, the FASB issued ASU No. 2015-02, “Consolidation (Topic 810) - Amendments to the Consolidated Analysis.” This ASU focuses on the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities. We adopted ASU No. 2015-02 effective January 1, 2016 with no impact to our financial statements.

ASU No. 2015-11

On July 22, 2015, the FASB issued ASU No. 2015-11, “Inventory (Topic 330): Simplifying the Measurement of Inventory.” This ASU requires entities to subsequently measure inventory at the lower of cost and net realizable value, and defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. ASU No. 2015-11 was effective January 1, 2017. We do not expect the effect of ASU No. 2015-11 to have a material impact on our financial statements.

ASU No. 2016-02

On February 25, 2016, the FASB issued ASU 2016-02, “Leases (Topic 842).” This ASU requires that lessees will be required to recognize assets and liabilities on the balance sheet for the present value of the rights and obligations created by all leases with terms of more than 12 months. The ASU also will require disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. ASU 2016-02 will be effective for us as of January 1, 2019. We are currently reviewing the effect of ASU No. 2016-02.

ASU No. 2016-05

On March 10, 2016, the FASB issued ASU 2016-05, “Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships.” This ASU clarifies that for the purposes of applying the guidance in Topic 815, a change in the counterparty to a derivative instrument that has been designated as the hedging instrument in an existing hedging relationship would not, in and of itself, be considered a termination of the derivative instrument. We adopted ASU 2016-05 in the first quarter of 2016 with no material impact to our financial statements.

ASU No. 2016-09

On March 30, 2016, the FASB issued ASU 2016-09, “Compensation - Stock Compensation (Topic 718).” This ASU was issued as part of the FASB’s simplification initiative and affects all entities that issue share-based payment awards to their employees. This ASU covers accounting for income taxes, forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. ASU No. 2016-09 was effective January 1, 2017. We do not expect the effect of ASU No. 2016-09 to have a material impact on our financial statements.

ASU No. 2016-13

On June 16, 2016, the FASB issued ASU 2016-13, “Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments.” This ASU modifies the impairment model to utilize an expected loss methodology in place of the currently used incurred loss methodology, which will result in the more timely recognition of losses. ASU No. 2016-13 will be effective for us as of January 1, 2020. We are currently reviewing the effect of ASU No. 2016-13.

ASU No. 2016-15

On August 26, 2016, the FASB issued ASU 2016-15, “Statement of Cash Flows - Classification of Certain Cash Receipts and Cash Payments (Topic 230).” This ASU is intended to reduce the diversity in practice around how certain transactions are classified within the statement of cash flows. We adopted ASU No. 2016-15 in the third quarter of 2016 with no material impact to our financial statements.

ASU No. 2016-18

On November 17, 2016, the FASB issued ASU 2016-18, “Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force).” This ASU requires the statement of cash flows to explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents are to be included with cash and cash equivalents when reconciling the beginning of period and end of period amounts shown on the statement of cash flows. ASU No. 2016-18 will be effective for us as of January 1, 2018. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2017-04

On January 26, 2017, the FASB issued ASU 2017-04, “ASU 2017-04 Simplifying the Test for Goodwill Impairment (Topic 350)” to simplify the accounting for goodwill impairment. The guidance removes Step 2 of the goodwill impairment test, which requires a hypothetical purchase price allocation. A goodwill impairment will now be the amount by which a reporting unit’s carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. ASU No. 2017-04 will be effective for us as of January 1, 2020. We are currently reviewing the effect of this ASU to our financial statements.

19. Guarantee of Securities of Subsidiaries

KMI, along with its direct subsidiary KMP, are issuers of certain public debt securities. KMI, KMP and substantially all of KMI’s wholly owned domestic subsidiaries, are parties to a cross guarantee agreement whereby each party to the agreement unconditionally guarantees, jointly and severally, the payment of specified indebtedness of each other party to the agreement. Accordingly, with the exception of certain subsidiaries identified as Subsidiary Non-Guarantors, the parent issuer, subsidiary issuer and other subsidiaries are all guarantors of each series of public debt. As a result of the cross guarantee agreement, a holder of any of the guaranteed public debt securities issued by KMI or KMP are in the same position with respect to the net assets, income and cash flows of KMI and the Subsidiary Issuer and Guarantors. The only amounts that are not available to the holders of each of the guaranteed public debt securities to satisfy the repayment of such securities are the net assets, income and cash flows of the Subsidiary Non-Guarantors.

In lieu of providing separate financial statements for subsidiary issuer and guarantor, we have included the accompanying condensed consolidating financial statements based on Rule 3-10 of the SEC's Regulation S-X. We have presented each of the parent and subsidiary issuer in separate columns in this single set of condensed consolidating financial statements.

On September 30, 2016, Copano (previously reflected as a Subsidiary Issuer and Guarantor) repaid the $332 million principal amount of its 7.125% senior notes due 2021. Copano continues to be a subsidiary guarantor under the cross guarantee agreement mentioned above. For all periods presented, financial statement balances and activities for Copano are now reflected within the Subsidiary Guarantor column, and the Subsidiary Issuer and Guarantor-Copano column has been eliminated.

On September 1, 2016, we sold a 50% equity interest in SNG (see further details discussed in Note 3, "Acquisitions and Divestitures"). Subsequent to the transaction, we deconsolidated SNG and now account for our equity interest in SNG as an equity investment. Our wholly owned subsidiary which holds our interest in SNG is reflected within the Subsidiary Guarantors column of these condensed consolidating financial statements.

Excluding fair value adjustments, as of December 31, 2016, Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, and Subsidiary Guarantors had $14,235 million, $19,485 million, and $4,191 million of Guaranteed Notes outstanding, respectively. Included in the Subsidiary Guarantors debt balance as presented in the accompanying December 31, 2016 condensed consolidating balance sheets are approximately $169 million of capitalized lease debt that is not subject to the cross guarantee agreement.

The accounts within the Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, Subsidiary Guarantors and Subsidiary Non-Guarantors are presented using the equity method of accounting for investments in subsidiaries, including subsidiaries that are guarantors and non-guarantors, for purposes of these condensed consolidating financial statements only. These intercompany investments and related activity eliminate in consolidation and are presented separately in the accompanying condensed consolidating balance sheets and statements of income and cash flows.

A significant amount of each Issuers' income and cash flow is generated by its respective subsidiaries. As a result, the funds necessary to meet its debt service and/or guarantee obligations are provided in large part by distributions or advances it receives from its respective subsidiaries. We utilize a centralized cash pooling program among our majority-owned and consolidated subsidiaries, including the Subsidiary Issuers and Guarantors and Subsidiary Non-Guarantors. The following Condensed Consolidating Statements of Cash Flows present the intercompany loan and distribution activity, as well as cash collection and payments made on behalf of our subsidiaries, as cash activities.

Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2016
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor-KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 34	$ —	$ 11,572	$ 1,511	$ (59)	$ 13,058
Operating Costs, Expenses and Other						
Costs of sales	—	—	3,245	266	(13)	3,498
Depreciation, depletion and amortization	18	—	1,872	319	—	2,209
Other operating expenses	725	(36)	2,390	746	(46)	3,779
Total Operating Costs, Expenses and Other	743	(36)	7,507	1,331	(59)	9,486
Operating (Loss) Income	(709)	36	4,065	180	—	3,572
Other Income (Expense)						
Earnings from consolidated subsidiaries	2,948	2,826	245	59	(6,078)	—
Losses from equity investments	—	—	(113)	—	—	(113)
Interest, net	(696)	90	(1,149)	(51)	—	(1,806)
Amortization of excess cost of equity investments and other, net	—	—	(20)	5	—	(15)
Income Before Income Taxes	1,543	2,952	3,028	193	(6,078)	1,638
Income Tax Expense	(835)	(5)	(33)	(44)	—	(917)
Net Income	708	2,947	2,995	149	(6,078)	721
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(13)	(13)
Net Income Attributable to Controlling Interests	708	2,947	2,995	149	(6,091)	708
Preferred Stock Dividends	(156)	—	—	—	—	(156)
Net Income Available to Common Stockholders	$ 552	$ 2,947	$ 2,995	$ 149	$ (6,091)	$ 552
Net Income	$ 708	$ 2,947	$ 2,995	$ 149	$ (6,078)	$ 721
Total other comprehensive (loss) income	(200)	(341)	(352)	55	638	(200)
Comprehensive income	508	2,606	2,643	204	(5,440)	521
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(13)	(13)
Comprehensive income attributable to controlling interests	$ 508	$ 2,606	$ 2,643	$ 204	$ (5,453)	$ 508

Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2015
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor-KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 37	$ —	$ 12,840	$ 1,575	$ (49)	$ 14,403
Operating Costs, Expenses and Other						
Costs of sales	—	—	3,747	367	1	4,115
Depreciation, depletion and amortization	22	—	1,929	358	—	2,309
Other operating expenses	71	38	4,714	759	(50)	5,532
Total Operating Costs, Expenses and Other	93	38	10,390	1,484	(49)	11,956
Operating (Loss) Income	(56)	(38)	2,450	91	—	2,447
Other Income (Expense)						
Earnings (losses) from consolidated subsidiaries	1,430	1,643	118	(30)	(3,161)	—
Earnings from equity investments	—	—	384	—	—	384
Interest, net	(686)	23	(1,345)	(43)	—	(2,051)
Amortization of excess cost of equity investments and other, net	—	1	(17)	8	—	(8)
Income Before Income Taxes	688	1,629	1,590	26	(3,161)	772
Income Tax Expense	(435)	(4)	(6)	(119)	—	(564)
Net Income (Loss)	253	1,625	1,584	(93)	(3,161)	208
Net Loss Attributable to Noncontrolling Interests	—	—	—	—	45	45
Net Income (Loss) Attributable to Controlling Interests	253	$ 1,625	$ 1,584	$ (93)	$ (3,116)	$ 253
Preferred Stock Dividends	(26)	$ —	$ —	$ —	$ —	$ (26)
Net Income (Loss) Available to Common Stockholders	$ 227	$ 1,625	$ 1,584	$ (93)	$ (3,116)	$ 227
Net Income (Loss)	$ 253	$ 1,625	$ 1,584	$ (93)	$ (3,161)	$ 208
Total other comprehensive loss	(444)	(460)	(325)	(326)	1,111	(444)
Comprehensive (loss) income	(191)	1,165	1,259	(419)	(2,050)	(236)
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	45	45
Comprehensive (loss) income attributable to controlling interests	$ (191)	$ 1,165	$ 1,259	$ (419)	$ (2,005)	$ (191)

Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2014
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 36	$ —	$ 14,575	$ 1,621	$ (6)	$ 16,226
Operating Costs, Expenses and Other						
Costs of sales	—	—	5,738	498	42	6,278
Depreciation, depletion and amortization	21	—	1,686	333	—	2,040
Other operating expenses	30	5	2,972	501	(48)	3,460
Total Operating Costs, Expenses and Other	51	5	10,396	1,332	(6)	11,778
Operating (Loss) Income	(15)	(5)	4,179	289	—	4,448
Other Income (Expense)						
Earnings from consolidated subsidiaries	2,080	3,977	443	1,120	(7,620)	—
Earnings (losses) from equity investments	—	—	407	(1)	—	406
Interest, net	(513)	(111)	(1,084)	(90)	—	(1,798)
Amortization of excess cost of equity investments and other, net	—	—	(13)	48	—	35
Income Before Income Taxes	1,552	3,861	3,932	1,366	(7,620)	3,091
Income Tax Expense	(278)	(7)	(71)	(292)	—	(648)
Net Income	1,274	3,854	3,861	1,074	(7,620)	2,443
Net Income Attributable to Noncontrolling Interests	(248)	(211)	—	—	(958)	(1,417)
Net Income Attributable to Controlling Interests	$ 1,026	$ 3,643	$ 3,861	$ 1,074	$ (8,578)	$ 1,026
Net Income	$ 1,274	$ 3,854	$ 3,861	$ 1,074	$ (7,620)	$ 2,443
Total other comprehensive (loss) income	(24)	275	288	(168)	(351)	20
Comprehensive income	1,250	4,129	4,149	906	(7,971)	2,463
Comprehensive income attributable to noncontrolling interests	(273)	(203)	—	—	(1,010)	(1,486)
Comprehensive income attributable to controlling interests	$ 977	$ 3,926	$ 4,149	$ 906	$ (8,981)	$ 977

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Condensed Consolidating Balance Sheets as of December 31, 2016
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS						
Cash and cash equivalents	$ 471	$ —	$ 9	$ 205	$ (1)	$ 684
Other current assets - affiliates	5,739	1,999	13,207	655	(21,600)	—
All other current assets	269	139	1,935	205	(3)	2,545
Property, plant and equipment, net	242	—	30,795	7,668	—	38,705
Investments	665	2	6,236	124	—	7,027
Investments in subsidiaries	26,907	29,421	4,307	4,028	(64,663)	—
Goodwill	13,789	22	5,167	3,174	—	22,152
Notes receivable from affiliates	516	21,608	1,132	412	(23,668)	—
Deferred income taxes	6,647	—	—	—	(2,295)	4,352
Other non-current assets	72	206	4,455	107	—	4,840
Total assets	$ 55,317	$ 53,397	$ 67,243	$ 16,578	$ (112,230)	$ 80,305
LIABILITIES AND STOCKHOLDERS' EQUITY						
Liabilities						
Current portion of debt	$ 1,286	$ 600	$ 687	$ 123	$ —	$ 2,696
Other current liabilities - affiliates	3,551	13,299	4,197	553	(21,600)	—
All other current liabilities	432	362	2,016	422	(4)	3,228
Long-term debt	13,308	19,277	4,095	674	—	37,354
Notes payable to affiliates	1,533	448	20,520	1,167	(23,668)	—
Deferred income taxes	—	—	681	1,614	(2,295)	—
Other long-term liabilities and deferred credits	776	111	821	517	—	2,225
Total liabilities	20,886	34,097	33,017	5,070	(47,567)	45,503
Stockholders' equity						
Total KMI equity	34,431	19,300	34,226	11,508	(65,034)	34,431
Noncontrolling interests	—	—	—	—	371	371
Total stockholders' equity	34,431	19,300	34,226	11,508	(64,663)	34,802
Total liabilities and stockholders' equity	$ 55,317	$ 53,397	$ 67,243	$ 16,578	$ (112,230)	$ 80,305

Condensed Consolidating Balance Sheets as of December 31, 2015
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS						
Cash and cash equivalents	$ 123	$ —	$ 12	$ 142	$ (48)	$ 229
Other current assets - affiliates	2,233	1,600	9,410	688	(13,931)	—
All other current assets	126	119	2,161	195	(6)	2,595
Property, plant and equipment, net	252	—	33,032	7,263	—	40,547
Investments	16	2	5,906	116	—	6,040
Investments in subsidiaries	27,401	28,038	3,493	3,320	(62,252)	—
Goodwill	15,089	22	5,508	3,171	—	23,790
Notes receivable from affiliates	850	21,319	2,092	358	(24,619)	—
Deferred income taxes	7,501	—	—	—	(2,178)	5,323
Other non-current assets	215	307	4,951	107	—	5,580
Total assets	$ 53,806	$ 51,407	$ 66,565	$ 15,360	$ (103,034)	$ 84,104
LIABILITIES AND STOCKHOLDERS' EQUITY						
Liabilities						
Current portion of debt	$ 67	$ 500	$ 132	$ 122	$ —	$ 821
Other current liabilities - affiliates	1,328	8,682	3,210	711	(13,931)	—
All other current liabilities	321	458	1,992	527	(54)	3,244
Long-term debt	13,845	20,053	7,825	683	—	42,406
Notes payable to affiliates	2,404	448	20,462	1,305	(24,619)	—
Deferred income taxes	—	—	596	1,582	(2,178)	—
All other long-term liabilities and deferred credits	722	193	909	406	—	2,230
Total liabilities	18,687	30,334	35,126	5,336	(40,782)	48,701
Stockholders' equity						
Total KMI equity	35,119	21,073	31,439	10,024	(62,536)	35,119
Noncontrolling interests	—	—	—	—	284	284
Total stockholders' equity	35,119	21,073	31,439	10,024	(62,252)	35,403
Total liabilities and stockholders' equity	$ 53,806	$ 51,407	$ 66,565	$ 15,360	$ (103,034)	$ 84,104

Condensed Consolidating Statements of Cash Flows for the Year Ended December 31, 2016
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	$ (3,989)	$ 4,980	$ 11,641	$ 885	$ (8,730)	$ 4,787
Cash flows from investing activities						
Acquisitions of assets and investments, net of cash acquired	(2)	—	(331)	—	—	(333)
Capital expenditures	(27)	—	(2,258)	(597)	—	(2,882)
Proceeds from sale of equity interests in subsidiaries, net	—	—	1,401	—	—	1,401
Sales of property, plant and equipment, investments and other net assets, net of removal costs	6	—	326	(2)	—	330
Contributions to investments	(343)	—	(54)	(11)	—	(408)
Distributions from equity investments in excess of cumulative earnings	2,417	298	190	—	(2,674)	231
Funding to affiliates	(2,820)	(535)	(5,062)	(727)	9,144	—
Other, net	—	(73)	39	(10)	—	(44)
Net cash used in investing activities	(769)	(310)	(5,749)	(1,347)	6,470	(1,705)
Cash flows from financing activities						
Issuances of debt	8,255	—	374	—	—	8,629
Payments of debt	(7,322)	(500)	(2,227)	(11)	—	(10,060)
Debt issue costs	(16)	—	(2)	(1)	—	(19)
Cash dividends - common shares	(1,118)	—	—	—	—	(1,118)
Cash dividends - preferred shares	(154)	—	—	—	—	(154)
Funding from affiliates	5,461	1,116	1,959	608	(9,144)	—
Contributions from parents	—	—	117	—	(117)	—
Contributions from noncontrolling interests	—	—	—	—	117	117
Distributions to parents	—	(5,286)	(6,116)	(73)	11,475	—
Distributions to noncontrolling interests	—	—	—	—	(24)	(24)
Net cash provided by (used in) financing activities	5,106	(4,670)	(5,895)	523	2,307	(2,629)
Effect of exchange rate changes on cash and cash equivalents	—	—	—	2	—	2
Net increase (decrease) in cash and cash equivalents	348	—	(3)	63	47	455
Cash and cash equivalents, beginning of period	123	—	12	142	(48)	229
Cash and cash equivalents, end of period	$ 471	$ —	$ 9	$ 205	$ (1)	$ 684

Condensed Consolidating Statements of Cash Flows for the Year Ended December 31, 2015
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	$ (4,218)	$ 6,824	$ 11,039	$ 347	$ (8,689)	$ 5,303
Cash flows from investing activities						
Acquisitions of assets and investments	(1,843)	—	(236)	—	—	(2,079)
Capital expenditures	(10)	—	(3,555)	(331)	—	(3,896)
Sales of property, plant and equipment, investments and other net assets, net of removal costs	—	—	39	—	—	39
Contributions to investments	(21)	—	(70)	(10)	5	(96)
Distributions from equity investments in excess of cumulative earnings	2,653	—	143	—	(2,568)	228
Investment in KMP	(159)	—	—	—	159	—
Funding to affiliates	(3,204)	(8,388)	(7,980)	(779)	20,351	—
Other, net	—	24	16	58	—	98
Net cash used in investing activities	(2,584)	(8,364)	(11,643)	(1,062)	17,947	(5,706)
Cash flows from financing activities						
Issuances of debt	14,316	—	—	—	—	14,316
Payments of debt	(14,048)	(675)	(383)	(10)	—	(15,116)
Debt issue costs	(24)	—	—	—	—	(24)
Issuances of common shares	3,870	—	—	—	—	3,870
Issuance of mandatory convertible preferred stock	1,541	—	—	—	—	1,541
Cash dividends - common shares	(4,224)	—	—	—	—	(4,224)
Repurchases of shares and warrants	(12)	—	—	—	—	(12)
Merger Transactions costs	(2)	—	—	—	—	(2)
Funding from affiliates	5,502	6,989	7,112	748	(20,351)	—
Contributions from parents	—	156	3	16	(175)	—
Contributions from noncontrolling interests	—	—	—	—	11	11
Distributions to parents	—	(4,944)	(6,133)	(166)	11,243	—
Distributions to noncontrolling interests	—	—	—	—	(34)	(34)
Other, net	2	(1)	—	—	—	1
Net cash provided by financing activities	6,921	1,525	599	588	(9,306)	327
Effect of exchange rate changes on cash and cash equivalents	—	—	—	(10)	—	(10)
Net increase (decrease) in cash and cash equivalents	119	(15)	(5)	(137)	(48)	(86)
Cash and cash equivalents, beginning of period	4	15	17	279	—	315

Cash and cash equivalents, end of period	$ 123	$ —	$ 12	$ 142	$ (48)	$ 229

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Condensed Consolidating Statements of Cash Flows for the Year Ended December 31, 2014
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash provided by operating activities	$ 1,419	$ 3,810	$ 6,059	$ 641	$ (7,462)	$ 4,467
Cash flows from investing activities						
Acquisitions of assets and investments	—	—	(1,370)	(18)	—	(1,388)
Capital expenditures	(1)	—	(2,911)	(705)	—	(3,617)
Sales of property, plant and equipment, investments, and other net assets, net of removal costs	—	—	(9)	14	—	5
Contributions to investments	—	(189)	(389)	—	189	(389)
Distributions from equity investments in excess of cumulative earnings	93	440	183	—	(534)	182
Investment in KMP	(550)	—	—	—	550	—
Drop down assets to KMP	875	(875)	—	—	—	—
Funding to affiliates	(1,949)	(6,644)	(3,826)	(784)	13,203	—
Other, net	—	27	29	(60)	1	(3)
Net cash used in investing activities	(1,532)	(7,241)	(8,293)	(1,553)	13,409	(5,210)
Cash flows from financing activities						
Issuances of debt	10,594	13,979	—	—	—	24,573
Payments of debt	(5,479)	(12,171)	(142)	(9)	—	(17,801)
Debt issue costs	(74)	(15)	—	—	—	(89)
Cash dividends - common shares	(1,760)	—	—	—	—	(1,760)
Repurchases of shares and warrants	(192)	—	—	—	—	(192)
Cash consideration of Merger Transactions	(3,937)	—	—	—	—	(3,937)
Merger Transactions costs	(74)	—	—	—	—	(74)
Funding from affiliates	956	4,129	7,241	877	(13,203)	—
Contributions from parents	—	1,912	533	64	(2,509)	—
Contributions from noncontrolling interests	—	—	—	—	1,767	1,767
Distributions to parents	—	(4,475)	(5,398)	(138)	10,011	—
Distributions to noncontrolling interests	—	—	—	—	(2,013)	(2,013)
Other, net	—	(1)	(2)	—	—	(3)
Net cash provided by financing activities	34	3,358	2,232	794	(5,947)	471
Effect of exchange rate changes on cash and cash equivalents	—	—	1	(12)	—	(11)
Net decrease in cash and cash equivalents	(79)	(73)	(1)	(130)	—	(283)
Cash and cash equivalents, beginning of period	83	88	18	409	—	598
Cash and cash equivalents, end of period	$ 4	$ 15	$ 17	$ 279	$ —	$ 315

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Supplemental Selected Quarterly Financial Data (Unaudited)

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
2016				
Revenues	$3,195	$3,144	$ 3,330	$ 3,389
Operating Income	816	940	882	934
Net Income (Loss)	314	375	(183)	215
Net Income (Loss) Attributable to Kinder Morgan, Inc.	315	372	(188)	209
Net Income (Loss) Available to Common Stockholders	276	333	(227)	170
Basic and Diluted Earnings (Loss) Per Common Share	0.12	0.15	(0.10)	0.08
2015				
Revenues	$3,597	$3,463	$ 3,707	$ 3,636
Operating Income (Loss)	1,078	892	721	(244)
Net Income (Loss)	419	342	183	(736)
Net Income (Loss) Attributable to Kinder Morgan, Inc.	429	333	186	(695)
Net Income (Loss) Available to Common Stockholders	429	333	186	(721)
Basic and Diluted Earnings (Loss) Per Common Share	0.20	0.15	0.08	(0.32)

Item 16. Form 10-K Summary.

Not Applicable.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

KINDER MORGAN, INC.
Registrant

By: /s/ Kimberly A. Dang
Kimberly A. Dang
Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: February 10, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ KIMBERLY A. DANG Kimberly A. Dang	Vice President and Chief Financial Officer (principal financial officer and principal accounting officer); Director	February 10, 2017
/s/ STEVEN J. KEAN Steven J. Kean	President and Chief Executive Officer (principal executive officer); Director	February 10, 2017
/s/ RICHARD D. KINDER Richard D. Kinder	Executive Chairman	February 10, 2017
/s/ TED A. GARDNER Ted A. Gardner	Director	February 10, 2017
/s/ ANTHONY W. HALL, JR. Anthony W. Hall, Jr.	Director	February 10, 2017
/s/ GARY L. HULTQUIST Gary L. Hultquist	Director	February 10, 2017
/s/ RONALD L. KUEHN, JR. Ronald L. Kuehn, Jr.	Director	February 10, 2017
/s/ DEBORAH A. MACDONALD Deborah A. Macdonald	Director	February 10, 2017
/s/ MICHAEL C. MORGAN Michael C. Morgan	Director	February 10, 2017
/s/ ARTHUR C. REICHSTETTER Arthur C. Reichstetter	Director	February 10, 2017
/s/ FAYEZ SAROFIM Fayez Sarofim	Director	February 10, 2017
/s/ C. PARK SHAPER C. Park Shaper	Director	February 10, 2017
/s/ WILLIAM A. SMITH William A. Smith	Director	February 10, 2017
/s/ JOEL V. STAFF Joel V. Staff	Director	February 10, 2017

/s/ ROBERT F. VAGT Robert F. Vagt	Director	February 10, 2017
/s/ PERRY M. WAUGHTAL Perry M. Waughtal	Director	February 10, 2017