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

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

		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

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.

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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

(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

(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

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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

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(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
	Low	High	Cash Dividends(a)
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

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(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

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(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

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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%

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%).

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

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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	$—	