KINDER MORGAN, INC.
Form 10-Q
April 21, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

F O R M 10-Q

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2017

or

o 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

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 Web site, 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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer" "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer þ Accelerated filer o Non-accelerated filer o Smaller reporting company o Emerging Growth Company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

As of April 20, 2017, the registrant had 2,232,442,396 Class P shares outstanding.

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KINDER MORGAN, INC. AND SUBSIDIARIES
GLOSSARY

Company Abbreviations

CIG	=	Colorado Interstate Gas Company, L.L.C.	KMI	=	Kinder Morgan, Inc. and its majority-owned and/or controlled subsidiaries
Copano	=	Copano Energy, L.L.C.			
CPG	=	Cheyenne Plains Gas Pipeline Company, L.L.C.	KMP	=	Kinder Morgan Energy Partners, L.P. and its majority-owned and controlled subsidiaries
Elba Express	=	Elba Express Company, L.L.C.			
EPB	=	El Paso Pipeline Partners, L.P. and its majority-owned and controlled subsidiaries	KMR	=	Kinder Morgan Management, LLC
			SFPP	=	SFPP, L.P.
EPNG	=	El Paso Natural Gas Company, L.L.C.	SLNG	=	Southern LNG Company, L.L.C.
Hiland	=	Hiland Partners, LP	SNG	=	Southern Natural Gas Company, L.L.C.
KMEP	=	Kinder Morgan Energy Partners, L.P.	TGP	=	Tennessee Gas Pipeline Company, L.L.C.
KMGP	=	Kinder Morgan G.P., Inc.			

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	EPA	=	United States Environmental Protection Agency
BBtu	=	billion British Thermal Units	FASB	=	Financial Accounting Standards Board
Bcf	=	billion cubic feet	FERC	=	Federal Energy Regulatory Commission
CERCLA	=	Comprehensive Environmental Response, Compensation and Liability Act	GAAP	=	United States Generally Accepted Accounting Principles
CO_2	=	carbon dioxide or our CO_2 business segment	LLC	=	limited liability company
DCF	=	distributable cash flow	MBbl	=	thousand barrels
DD&A	=	depreciation, depletion and amortization	MMBbl	=	million barrels
EBDA	=	earnings before depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments	NGL	=	natural gas liquids
			OTC	=	over-the-counter

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,” “position,” “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 or to pay dividends are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict.

See “Information Regarding Forward-Looking Statements” and Part I, Item 1A. “Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2016 (2016 Form 10-K) for a more detailed description of factors that may affect the forward-looking statements. You should keep these risk factors in mind when considering forward-looking statements. These risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. Because of these risks and uncertainties, you should not place undue reliance on any forward-looking statement. We plan to provide updates to projections included in this report when we believe previously disclosed projections no longer have a reasonable basis.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

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

	Three Months Ended March 31,	
	2017	2016
Revenues		
Natural gas sales	$809	$543
Services	1,977	2,114
Product sales and other	638	538
Total Revenues	3,424	3,195
Operating Costs, Expenses and Other		
Costs of sales	1,081	731
Operations and maintenance	513	565
Depreciation, depletion and amortization	558	551
General and administrative	181	190
Taxes, other than income taxes	104	108
Loss on impairments and divestitures, net	6	235
Other expense (income), net	1	(1)
Total Operating Costs, Expenses and Other	2,444	2,379
Operating Income	980	816
Other Income (Expense)		
Earnings from equity investments	175	100
Loss on impairments and divestitures of equity investments, net	—	(6)
Amortization of excess cost of equity investments	(15)	(14)
Interest, net	(465)	(441)
Other, net	16	13
Total Other Expense	(289)	(348)
Income Before Income Taxes	691	468
Income Tax Expense	(246)	(154)
Net Income	445	314
Net (Income) Loss Attributable to Noncontrolling Interests	(5)	1
Net Income Attributable to Kinder Morgan, Inc.	440	315
Preferred Stock Dividends	(39)	(39)
Net Income Available to Common Stockholders	$401	$276

Class P Shares		
Basic Earnings Per Common Share	$0.18	$0.12
Basic Weighted Average Common Shares Outstanding	2,230	2,229
Diluted Earnings Per Common Share	$0.18	$0.12
Diluted Weighted Average Common Shares Outstanding	2,230	2,229
Dividends Per Common Share Declared for the Period	$0.125	$0.125

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

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

	Three Months Ended March 31,	
	2017	2016
Net income	$445	$314
Other comprehensive income (loss), net of tax		
Change in fair value of hedge derivatives (net of tax expense of $(39) and $(43), respectively)	70	73
Reclassification of change in fair value of derivatives to net income (net of tax benefit of $12 and $64, respectively)	(21)	(108)
Foreign currency translation adjustments (net of tax expense of $(7) and $(45), respectively)	13	78
Benefit plan adjustments (net of tax expense of $(5) and $(3), respectively)	6	4
Total other comprehensive income	68	47
Comprehensive income	513	361
Comprehensive (income) loss attributable to noncontrolling interests	(5)	1
Comprehensive income attributable to Kinder Morgan, Inc.	$508	$362

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

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

	March 31, 2017 (Unaudited)	December 31, 2016
ASSETS		
Current Assets		
Cash and cash equivalents	$ 396	$ 684
Restricted deposits	90	103
Accounts receivable, net	1,263	1,370
Fair value of derivative contracts	213	198
Inventories	380	357
Income tax receivable	177	180
Other current assets	156	337
Total current assets	2,675	3,229
Property, plant and equipment, net	39,023	38,705
Investments	7,136	7,027
Goodwill	22,154	22,152
Other intangibles, net	3,263	3,318
Deferred income taxes	4,064	4,352
Deferred charges and other assets	1,478	1,522
Total Assets	$ 79,793	$ 80,305
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current Liabilities		
Current portion of debt	$ 3,928	$ 2,696
Accounts payable	1,214	1,257
Accrued interest	444	625
Accrued contingencies	264	261
Other current liabilities	839	1,085
Total current liabilities	6,689	5,924
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	34,285	36,105
Preferred interest in general partner of KMP	100	100
Debt fair value adjustments	1,079	1,149
Total long-term debt	35,464	37,354
Other long-term liabilities and deferred credits	2,635	2,225
Total long-term liabilities and deferred credits	38,099	39,579
Total Liabilities	44,788	45,503
Commitments and contingencies (Notes 3 and 9)		
Stockholders’ Equity		
Class P shares, $0.01 par value, 4,000,000,000 shares authorized, 2,230,149,554 and 2,230,102,384 shares, respectively, issued and outstanding	22	22
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 9.75% Series A Mandatory Convertible, $1,000 per share liquidation preference, 1,600,000 shares issued and outstanding	—	—
Additional paid-in capital	41,756	41,739
Retained deficit	(6,540)	(6,669)

Accumulated other comprehensive loss	(593)	(661)
Total Kinder Morgan, Inc.'s stockholders' equity	34,645	34,431
Noncontrolling interests	360	371
Total Stockholders' Equity	35,005	34,802
Total Liabilities and Stockholders' Equity	$ 79,793	$ 80,305

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

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

	Three Months Ended March 31, 2017	2016
Cash Flows From Operating Activities		
Net income	$445	$314
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	558	551
Deferred income taxes	244	179
Amortization of excess cost of equity investments	15	14
Change in fair market value of derivative contracts	(6)	(30)
Loss on impairments and divestitures, net	6	235
Loss on impairments and divestitures of equity investments, net	—	6
Earnings from equity investments	(175)	(100)
Distributions from equity investment earnings	102	91
Changes in components of working capital, net of the effects of acquisitions and dispositions		
Accounts receivable, net	105	116
Inventories	(35)	46
Other current assets	10	14
Accounts payable	(35)	(172)
Accrued interest, net of interest rate swaps	(165)	(159)
Accrued contingencies and other current liabilities	(146)	(23)
Rate reparations, refunds and other litigation reserve adjustments	—	31
Other, net	(37)	(63)
Net Cash Provided by Operating Activities	886	1,050
Cash Flows From Investing Activities		
Acquisitions of assets and investments, net of cash acquired	(4)	(330)
Capital expenditures	(664)	(811)
Sales of property, plant and equipment, and other net assets, net of removal costs	71	(6)
Contributions to investments	(191)	(44)
Distributions from equity investments in excess of cumulative earnings	138	43
Other, net	13	4
Net Cash Used in Investing Activities	(637)	(1,144)
Cash Flows From Financing Activities		
Issuances of debt	1,517	4,610
Payments of debt	(2,122)	(4,336)
Debt issue costs	(1)	(6)
Cash dividends - common shares	(280)	(279)
Cash dividends - preferred shares	(39)	(37)
Contributions from investment partner	391	—
Contributions from noncontrolling interests	6	87
Distributions to noncontrolling interests	(9)	(4)
Other, net	(1)	—

Net Cash (Used in) Provided by Financing Activities	(538)	35
Effect of Exchange Rate Changes on Cash and Cash Equivalents	1	5
Net decrease in Cash and Cash Equivalents	(288)	(54)
Cash and Cash Equivalents, beginning of period	684	229
Cash and Cash Equivalents, end of period	$396	$175
Non-cash Investing and Financing Activities		
Assets acquired by the assumption or incurrence of liabilities	$—	$43
Supplemental Disclosures of Cash Flow Information		
Cash paid during the period for interest (net of capitalized interest)	$643	$659
Cash refund during the period for income taxes, net	(2)	(2)

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

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

	Common stock Issued shares	Common stock Par value	Preferred stock Issued shares	Preferred stock Par value	Additional paid-in capital	Retained deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
Balance at December 31, 2016	2,230	$ 22	2	$ —	$ 41,739	$ (6,669)	$ (661)	$ 34,431	$ 371	$ 34,802
Restricted shares					18			18		18
Net income						440		440	5	445
Distributions								—	(9)	(9)
Contributions								—	6	6
Preferred stock dividends						(39)		(39)		(39)
Common stock dividends						(280)		(280)		(280)
Impact of adoption of ASU 2016-09 (See Note 8)						8		8		8
Other					(1)			(1)	(13)	(14)
Other comprehensive income							68	68		68
Balance at March 31, 2017	2,230	$ 22	2	$ —	$ 41,756	$ (6,540)	$ (593)	$ 34,645	$ 360	$ 35,005

	Common stock Issued shares	Common stock Par value	Preferred stock Issued shares	Preferred stock Par value	Additional paid-in capital	Retained deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
Balance at December 31, 2015	2,229	$ 22	2	$ —	$ 41,661	$ (6,103)	$ (461)	$ 35,119	$ 284	$ 35,403
Restricted shares					17			17		17
Net income						315		315	(1)	314
Distributions								—	(4)	(4)
Contributions								—	87	87
Preferred stock dividends						(39)		(39)		(39)
Common stock dividends						(279)		(279)		(279)
Other comprehensive income							47	47		47
Balance at March 31, 2016	2,229	$ 22	2	$ —	$ 41,678	$ (6,106)	$ (414)	$ 35,180	$ 366	$ 35,546

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

KINDER MORGAN, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. General

Organization

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.

Basis of Presentation

General

Our reporting currency is U.S. dollars, and all references to dollars are U.S. dollars, unless stated otherwise. Our accompanying unaudited consolidated financial statements have been prepared under the rules and regulations of the United States Securities and Exchange Commission (SEC). These rules and regulations conform to the accounting principles contained in the FASB’s Accounting Standards Codification, the single source of GAAP. Under such rules and regulations, all significant intercompany items have been eliminated in consolidation.

In our opinion, all adjustments, which are of a normal and recurring nature, considered necessary for a fair presentation of our financial position and operating results for the interim periods have been included in the accompanying consolidated financial statements, and certain amounts from prior periods have been reclassified to conform to the current presentation. Interim results are not necessarily indicative of results for a full year; accordingly, you should read these consolidated financial statements in conjunction with our consolidated financial statements and related notes included in our 2016 Form 10-K.

Impairments and Losses on Divestitures

During the three months ended March 31, 2017 and 2016, we recorded non-cash pre-tax losses on impairments and divestitures netting to $6 million and $235 million, respectively. The three months ended March 31, 2017 and 2016 included net losses of $6 million and $11 million on miscellaneous asset disposals. The three months ended March 31, 2016 also included $191 million of project write-offs across our Natural Gas Pipelines, CO_2, and Products Pipelines business segments, along with $20 million of impairments related to certain coal facilities in our Terminals business segment and a $13 million loss related to the sale of a Transmix facility in our Products Pipelines business segment.

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

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

Earnings per Share

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

The following table sets forth the allocation of net income available to shareholders of Class P shares and participating securities (in millions):

	Three Months Ended March 31,	
	2017	2016
Class P shares	$399	$275
Participating securities:		
Restricted stock awards(a)	2	1
Net Income Available to Common Stockholders	$401	$276

(a) As of March 31, 2017, there were approximately 9 million restricted stock awards.

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

	Three Months Ended March 31,	
	2017	2016
Unvested restricted stock awards	9	8
Warrants to purchase our Class P shares(a)	293	293
Convertible trust preferred securities	8	8
Mandatory convertible preferred stock(b)	58	58

(a) Each warrant entitles the holder to purchase one share of our common stock for an exercise price of $40 per share, payable in cash or by cashless exercise, at any time until May 25, 2017. The potential dilutive effect of the warrants does not consider the assumed proceeds to KMI upon exercise.
(b) Until our mandatory convertible preferred shares are converted to common shares, on or before the expected mandatory conversion date of October 26, 2018, the holder of each preferred share participates in our earnings by receiving preferred dividends.

2. Divestiture

Sale of Interest in Elba Liquefaction Company L.L.C. (ELC)

Effective February 28, 2017, we sold a 49% partnership interest in ELC to investment funds managed by EIG Global Energy Partners (EIG). We continue to own a 51% controlling interest in and operate ELC. Under the terms of ELC's limited liability company agreement, we are responsible for placing in service and operating certain supply pipelines and terminal facilities that support the operations of ELC and which are wholly owned by us. In certain limited circumstances which are not expected to occur, EIG has the right to relinquish its interest in ELC and redeem its capital account. We have, as a result of these contingencies, reflected the $391 million of total contributions from EIG, consisting of $387 million of proceeds from the sale and $4 million as an additional contribution for March 2017 capital expenditures, as a deferred credit within “Other long-term liabilities and deferred credits” on our consolidated balance sheet as of March 31, 2017. EIG is not entitled to any specified return on its capital. Once these contingencies expire, EIG’s capital account will be reflected as noncontrolling interest on our balance sheet.

3. Debt

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

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

	March 31, 2017	December 31, 2016
Unsecured term loan facility, variable rate, due January 26, 2019	$ 1,000	$ 1,000
Senior notes, 1.50% through 8.05%, due 2017 through 2098(a)	13,253	13,236
Credit facility due November 26, 2019	—	—
Commercial paper borrowings	—	—
KMP senior notes, 2.65% through 9.00%, due 2017 through 2044(b)	18,885	19,485
TGP senior notes, 7.00% through 8.375%, due 2017 through 2037	1,540	1,540
EPNG senior notes, 5.95% through 8.625%, due 2017 through 2032	1,115	1,115
CIG senior notes, 4.15% and 6.85%, due 2026 and 2037	475	475
Kinder Morgan Finance Company, LLC, senior notes, 6.00% and 6.40%, due 2018 and 2036	786	786
Hiland Partners Holdings LLC, senior note, 5.50%, due 2022	225	225
EPC Building, LLC, promissory note, 3.967%, due 2017 through 2035	430	433
Trust I preferred securities, 4.75%, due March 31, 2028	221	221
KMGP, $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock	100	100
Other miscellaneous debt	283	285
Total debt – KMI and Subsidiaries	38,313	38,901
Less: Current portion of debt(c)	3,928	2,696
Total long-term debt – KMI and Subsidiaries(d)	$ 34,385	$ 36,205

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(a) Amount includes senior notes that are denominated in Euros and have been converted to U.S. dollars and are respectively reported above at the March 31, 2017 exchange rate of 1.0652 U.S. dollars per Euro and the December 31, 2016 exchange rate of 1.0517 U.S. dollars per Euro. For the three months ended March 31, 2017, our debt balance increased by $17 million as a result of the change in the exchange rate of U.S. dollars per Euro. The increase in debt due to the changes in exchange rates is offset by a corresponding change in the value of cross-currency swaps reflected in “Deferred charges and other assets” and “ Other long-term liabilities and deferred credits” on our consolidated balance sheets. At the time of issuance, we entered into cross-currency swap agreements associated with these senior notes, effectively converting these Euro-denominated senior notes to U.S. dollars (see Note 5 “Risk Management—Foreign Currency Risk Management”).

(b) In February 2017, we repaid $600 million of maturing 6.00% senior notes.

(c) Amounts include outstanding credit facility borrowings, commercial paper borrowings and other debt maturing within 12 months (see “—Current Portion of Debt” below).

(d) Excludes our “Debt fair value adjustments” which, as of March 31, 2017 and December 31, 2016, increased our combined debt balances by $1,079 million and $1,149 million, respectively. In addition to all unamortized debt discount/premium amounts, debt issuance costs and purchase accounting on our debt balances, our debt fair value adjustments also include amounts associated with the offsetting entry for hedged debt and any unamortized portion of proceeds received from the early termination of interest rate swap agreements.

We and substantially all of our wholly owned domestic subsidiaries are a party to a cross guarantee agreement whereby each party to the agreement unconditionally guarantees, jointly and severally, the payment of specified indebtedness of each other party to the agreement. Also, see Note 11.

Credit Facilities

As of March 31, 2017, we had $4,881 million available under our $5.0 billion revolving credit agreement, which is net of $119 million in letters of credit. Borrowings under our revolving credit facility can be used for working capital and other general corporate purposes and as a backup to our commercial paper program. Borrowings under our commercial paper program reduce the borrowings allowed under our credit facility.

Current Portion of Debt
Our current portion of debt as of March 31, 2017, primarily includes the following significant series of long-term notes maturing within the next 12 months:

$300 million 7.50% notes due April 2017
$355 million 5.95% notes due April 2017
$786 million 7.00% notes due June 2017
$500 million 2.00% notes due December 2017
$750 million 6.00% notes due January 2018
$82 million 7.00% notes due February 2018
$975 million 5.95% notes due February 2018

Subsequent Event—Debt Repayments

In April 2017, we repaid $300 million of maturing 7.50% TGP senior notes and $355 million of maturing 5.95% EPNG senior notes listed above in current portion of debt as of March 31, 2017.
4. Stockholders' Equity

Common Equity

As of March 31, 2017, our common equity consisted of our Class P common stock. For additional information regarding our Class P common stock, see Note 11 to our consolidated financial statements included in our 2016 Form 10-K.

Common Dividends

Holders of our common stock participate in any dividend declared by our board of directors, subject to the rights of the holders of any outstanding preferred stock. Our per share dividends declared for and paid in the periods ended March 31, 2017 and 2016 were $0.125 per share. On April 19, 2017, our board of directors declared a cash dividend of $0.125 per common share for the quarterly period ended March 31, 2017, which is payable on May 15, 2017 to common shareholders of record as of May 1, 2017.

Mandatory Convertible Preferred Stock

We have issued and outstanding 1,600,000 shares of 9.750% Series A mandatory convertible preferred stock, with a liquidating preference of $1,000 per share. For additional information regarding our mandatory convertible preferred stock, see Note 11 to our consolidated financial statements included in our 2016 Form 10-K.

Preferred Dividends

On January 18, 2017, our board of directors declared a cash dividend of $24.375 per share of our mandatory convertible preferred stock (equivalent of $1.21875 per depositary share) for the period from and including January 26, 2017 through and including April 25, 2017, which is payable on April 26, 2017 to mandatory convertible preferred shareholders of record as of April 11, 2017.

5. Risk Management

Certain of our business activities expose us to risks associated with unfavorable changes in the market price of natural gas, NGL and crude oil. We also have exposure to interest rate and foreign currency risk as a result of the issuance of our debt obligations. Pursuant to our management's approved risk management policy, we use derivative contracts to hedge or reduce our exposure to some of these risks. In addition, prior to May 2016, we had power forward and swap contracts related to legacy operations of acquired businesses.

Energy Commodity Price Risk Management

As of March 31, 2017, we had the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Net open position long/(short)	
Derivatives designated as hedging contracts		
Crude oil fixed price	(19.4)	MMBbl
Crude oil basis	(3.3)	MMBbl
Natural gas fixed price	(50.3)	Bcf
Natural gas basis	(21.1)	Bcf
Derivatives not designated as hedging contracts		
Crude oil fixed price	(1.3)	MMBbl
Crude oil basis	(0.5)	MMBbl
Natural gas fixed price	1.5	Bcf
Natural gas basis	2.2	Bcf
NGL and other fixed price	(5.8)	MMBbl

As of March 31, 2017, the maximum length of time over which we have hedged, for accounting purposes, our exposure to the variability in future cash flows associated with energy commodity price risk is through December 2021.

Interest Rate Risk Management

As of March 31, 2017 and December 31, 2016, we had a combined notional principal amount of $9,575 million and $9,775 million, respectively, of fixed-to-variable interest rate swap agreements, all of which were designated as fair value hedges. All of our swap agreements effectively convert the interest expense associated with certain series of senior notes from fixed rates to variable rates based on an interest rate of London Interbank Offered Rate plus a spread and have termination dates that correspond to the maturity dates of the related series of senior notes. As of March 31, 2017, the maximum length of time over which we have hedged a portion of our exposure to the variability in the value of this debt due to interest rate risk is through March 15, 2035.

Foreign Currency Risk Management

As of March 31, 2017, we had a notional principal amount of $1,358 million of cross-currency swap agreements to manage the foreign currency risk related to our Euro denominated senior notes by effectively converting all of the fixed-rate Euro denominated debt, including annual interest payments and the payment of principal at maturity, to U.S. dollar denominated debt at fixed rates equivalent to approximately 3.79% and 4.67% for the 7-year and 12-year senior notes, respectively. These cross-currency swaps are accounted for as cash flow hedges. The terms of the cross-currency swap agreements correspond to the related hedged senior notes, and such agreements have the same maturities as the hedged senior notes.

Fair Value of Derivative Contracts

The following table summarizes the fair values of our derivative contracts included in our accompanying consolidated balance sheets (in millions):

Fair Value of Derivative Contracts

		Asset derivatives		Liability derivatives	
		March 31, 2017	December 31, 2016	March 31, 2017	December 31, 2016
	Location	Fair value		Fair value	
Derivatives designated as hedging contracts					
Natural gas and crude derivative contracts	Fair value of derivative contracts/(Other current liabilities)	$119	$ 101	$(22)	$ (57)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	81	70	(7)	(24)
Subtotal		200	171	(29)	(81)
Interest rate swap agreements	Fair value of derivative contracts/(Other current liabilities)	86	94	—	—
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	175	206	(57)	(57)
Subtotal		261	300	(57)	(57)
Cross-currency swap agreements	Fair value of derivative contracts/(Other current liabilities)	—	—	(30)	(7)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	7	—	(5)	(24)
Subtotal		7	—	(35)	(31)
Total		468	471	(121)	(169)
Derivatives not designated as hedging contracts					
Natural gas, crude, NGL and other derivative contracts	Fair value of derivative contracts/(Other current liabilities)	8	3	(10)	(29)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	—	(1)	(1)
Subtotal		8	3	(11)	(30)
Total		8	3	(11)	(30)
Total derivatives		$476	$ 474	$(132)	$ (199)

Effect of Derivative Contracts on the Income Statement

The following tables summarize the impact of our derivative contracts in our accompanying consolidated statements of income (in millions):

Derivatives in fair value hedging relationships	Location	Gain/(loss) recognized in income on derivatives and related hedged item Three Months Ended March 31,	
		2017	2016
Interest rate swap agreements	Interest, net	$(39)	$280
Hedged fixed rate debt	Interest, net	$36	$(284)

Derivatives in cash flow hedging relationships	Gain/(loss) recognized in OCI on derivative (effective portion)(a)		Location	Gain/(loss) reclassified from Accumulated OCI into income (effective portion)(b)		Location	Gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	
	Three Months Ended March 31,			Three Months Ended March 31,			Three Months Ended March 31,	
	2017	2016		2017	2016		2017	2016
Energy commodity derivative contracts	$ 68	$ 27	Revenues—Natural gas sales	$ 2	$ 21	Revenues—Natural gas sales	$ —	$ —
			Revenues—Product sales and other	6	57	Revenues—Product sales and other	3	1
			Costs of sales	3	(10)	Costs of sales	—	—
Interest rate swap agreements(c)	—	(4)	Interest, net	—	(1)	Interest, net	—	—
Cross-currency swap	2	50	Other, net	10	41	Other, net	—	—
Total	$ 70	$ 73	Total	$ 21	$ 108	Total	$ 3	$ 1

(a) We expect to reclassify an approximate $25 million gain associated with cash flow hedge price risk management activities included in our accumulated other comprehensive loss balances as of March 31, 2017 into earnings during the next twelve months (when the associated forecasted transactions are also expected to occur), however, actual amounts reclassified into earnings could vary materially as a result of changes in market prices.

(b) Amounts reclassified were the result of the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchases actually occurred).

(c) Amounts represent our share of an equity investee's accumulated other comprehensive loss.

Derivatives not designated as accounting hedges Location

		Gain/(loss) recognized in income on derivatives Three Months Ended March 31,	
		2017	2016
Energy commodity derivative contracts	Revenues—Natural gas sales	$ 6	$ 6
	Revenues—Product sales and other	12	(2)
	Costs of sales	—	(5)
Interest rate swap agreements	Interest, net	—	53
Total(a)		$ 18	$ 52

(a) The three months ended March 31, 2017 and 2016 include approximate gains of $12 million and $19 million, respectively, associated with natural gas, crude and NGL derivative contract settlements.

Credit Risks

In conjunction with certain derivative contracts, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of March 31, 2017 and December 31, 2016, we had no outstanding letters of credit supporting our commodity price risk management program. As of March 31, 2017 and December 31, 2016, we had cash margins of $26 million and $37 million, respectively, posted by us with our counterparties as collateral and no amounts posted by our counterparties as collateral. The balance at March 31, 2017, consisted of initial margin requirements of $15 million and variation margin requirements of $11 million. We also use industry standard commercial agreements which allow for the netting of exposures associated with transactions executed under a single commercial agreement. Additionally, we generally utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring the posting of additional collateral upon a decrease in our credit rating. As of March 31, 2017, based on our current mark to market positions and posted collateral, we estimate that if our credit rating were downgraded one or two notches we would not be required to post additional collateral.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Loss

Cumulative revenues, expenses, gains and losses that under GAAP are included within our comprehensive income but excluded from our earnings are reported as “Accumulated other comprehensive loss” within “Stockholders’ Equity” in our consolidated balance sheets. Changes in the components of our “Accumulated other comprehensive loss” not including non-controlling interests are summarized as follows (in millions):

	Net unrealized gains/(losses) on cash flow hedge derivatives	Foreign currency translation adjustments	Pension and other postretirement liability adjustments	Total accumulated other comprehensive loss
Balance as of December 31, 2016	$ (1)	$ (288)	$ (372)	$ (661)
Other comprehensive gain before reclassifications	70	13	6	89
Gains reclassified from accumulated other comprehensive loss	(21)	—	—	(21)
Net current-period other comprehensive income	49	13	6	68
Balance as of March 31, 2017	$ 48	$ (275)	$ (366)	$ (593)

	Net unrealized gains/(losses) on cash flow hedge derivatives	Foreign currency translation adjustments	Pension and other postretirement liability adjustments	Total accumulated other comprehensive loss
Balance as of December 31, 2015	$ 219	$ (322)	$ (358)	$ (461)
Other comprehensive gain before reclassifications	73	78	4	155
Gains reclassified from accumulated other comprehensive loss	(108)	—	—	(108)
Net current-period other comprehensive (loss) income	(35)	78	4	47
Balance as of March 31, 2016	$ 184	$ (244)	$ (354)	$ (414)

6. Fair Value

The fair values of our financial instruments are separated into three broad levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. Each fair value measurement must be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety.

The three broad levels of inputs defined by the fair value hierarchy are as follows:

- Level 1 Inputs—quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;
- Level 2 Inputs—inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability; and
- Level 3 Inputs—unobservable inputs for the asset or liability. These unobservable inputs reflect the entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability, and are developed based on the best information available in the circumstances (which might include the reporting entity's own data).

Fair Value of Derivative Contracts

The following two tables summarize the fair value measurements of our (i) energy commodity derivative contracts; (ii) interest rate swap agreements; and (iii) cross-currency swap agreements, based on the three levels established by the Codification (in millions). The tables also identify the impact of derivative contracts which we have elected to present on our accompanying consolidated balance sheets on a gross basis that are eligible for netting under master netting agreements.

	Balance sheet asset fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Cash collateral held	Net amount
As of March 31, 2017							
Energy commodity derivative contracts(a)	$3	$205	$ —	$ 208	$ (19)	$ —	$ 189
Interest rate swap agreements	—	261	—	261	(26)	—	235
Cross-currency swap agreements	—	7	—	7	(7)	—	—
As of December 31, 2016							
Energy commodity derivative contracts(a)	$6	$168	$ —	$ 174	$ (43)	$ —	$ 131
Interest rate swap agreements	—	300	—	300	(18)	—	282

	Balance sheet liability fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Collateral posted(b)	Net amount
As of March 31, 2017							
Energy commodity derivative contracts(a)	$(13)	$(27)	$ —	$ (40)	$ 19	$ 11	$ (10)
Interest rate swap agreements	—	(57)	—	(57)	26	—	(31)
Cross-currency swap agreements	—	(35)	—	(35)	7	—	(28)
As of December 31, 2016							
Energy commodity derivative contracts(a)	$(29)	$(82)	$ —	$ (111)	$ 43	$ 37	$ (31)
Interest rate swap agreements	—	(57)	—	(57)	18	—	(39)
Cross-currency swap agreements	—	(31)	—	(31)	—	—	(31)

(a) Level 1 consists primarily of New York Mercantile Exchange natural gas futures. Level 2 consists primarily of OTC West Texas Intermediate swaps and options.

(b) Cash margin deposits posted by us associated with our energy commodity contract positions and OTC swap agreements and reported within "Restricted deposits" on our accompanying consolidated balance sheets. Any cash collateral paid or received is reflected in this table, but only to the extent that it represents variation margins. Any amount associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from this table.

The table below provides a summary of changes in the fair value of our Level 3 energy commodity derivative contracts (in millions):

Significant unobservable inputs (Level 3)

	Three Months Ended March 31,	
	2017	2016
Derivatives-net asset (liability)		
Beginning of Period	$—	$(15)
Total gains or (losses) included in earnings	—	(6)
Settlements	—	19
End of Period	$—	$(2)
The amount of total gains or (losses) for the period included in earnings attributable to the change in unrealized gains or (losses) relating to assets held at the reporting date	$—	$1

As of March 31, 2016, our Level 3 derivative assets and liabilities consisted primarily of power derivative contracts (which expired in April 2016), where a significant portion of fair value is calculated from underlying market data that is not readily observable. The derived values use industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management’s best estimate of fair value, and management would not expect materially different valuation results were we to use different input amounts within reasonable ranges.

Fair Value of Financial Instruments

The carrying value and estimated fair value of our outstanding debt balances are disclosed below (in millions):

	March 31, 2017		December 31, 2016	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Total debt	$39,392	$40,467	$40,050	$41,015

We used Level 2 input values to measure the estimated fair value of our outstanding debt balances as of both March 31, 2017 and December 31, 2016.

7. Reportable Segments

Segment results for the three months ended March 31, 2016 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.

Financial information by segment follows (in millions):

	Three Months Ended March 31,	
	2017	2016
Revenues		
Natural Gas Pipelines		
Revenues from external customers	$2,168	$1,970
Intersegment revenues	3	1
CO_2	303	302
Terminals	487	465
Products Pipelines		
Revenues from external customers	398	391
Intersegment revenues	4	5
Kinder Morgan Canada	59	59
Corporate and intersegment eliminations(a)	2	2
Total consolidated revenues	$3,424	$3,195

	Three Months Ended March 31,	
	2017	2016
Segment EBDA(b)		
Natural Gas Pipelines	$1,055	$994
CO_2	218	187
Terminals	307	260
Products Pipelines	287	177
Kinder Morgan Canada	43	46
Total Segment EBDA	1,910	1,664
DD&A	(558)	(551)
Amortization of excess cost of equity investments	(15)	(14)
General and administrative and corporate charges	(181)	(190)
Interest expense, net	(465)	(441)
Income tax expense	(246)	(154)
Total consolidated net income	$445	$314

	March 31, 2017	December 31, 2016
Assets		
Natural Gas Pipelines	$50,418	$ 50,428
CO_2	4,104	4,065
Terminals	9,809	9,725
Products Pipelines	8,353	8,329
Kinder Morgan Canada	1,638	1,572
Corporate assets(c)	5,469	6,108
Assets held for sale	2	78
Total consolidated assets	$79,793	$ 80,305

(a) Includes a management fee for services we perform as operator of an equity investee.
(b) Includes revenues, earnings from equity investments, other, net, less operating expenses, and other (income) expense, net, loss on impairments and divestitures, net and loss on impairments and divestitures of equity

investments, net.

(c) Includes cash and cash equivalents, margin and restricted deposits, certain prepaid assets and deferred charges, including income tax related assets, risk management assets related to debt fair value adjustments, corporate headquarters in Houston, Texas and miscellaneous corporate assets (such as information technology, telecommunications equipment and legacy operations) not allocated to the reportable segments.

8. Income Taxes

Income tax expense included in our accompanying consolidated statements of income were as follows (in millions, except percentages):

	Three Months Ended March 31,	
	2017	2016
Income tax expense	$246	$154
Effective tax rate	35.6 %	32.9 %

The effective tax rate for the three months ended March 31, 2017 is slightly higher than the statutory federal rate of 35% primarily due to state and foreign income taxes, partially offset by dividend-received deductions from our investment in Florida Gas Transmission Company (Citrus) and Plantation Pipe Line.

The effective tax rate for the three months ended March 31, 2016 is lower than the statutory federal rate of 35% primarily due to dividend-received deductions from our investment in Citrus and adjustments to our income tax reserve for uncertain tax positions, partially offset by state and foreign income taxes.

Adoption of ASU 2016-09“Compensation - Stock Compensation (Topic 718)”

The tax impact of ASU 2016-09, which was adopted and effective January 1, 2017, resulted in $8 million of deferred tax assets being recorded through a cumulative-effect adjustment to our retained deficit. The previously unrecorded deferred tax asset is related to net operating loss carryovers as a result of the delayed recognition of a windfall tax benefit related to share-based compensation. Post-adoption the excess tax benefits or deficiencies are recognized for income tax purposes in the period in which they occur through the income statement.

9. Litigation, Environmental and Other Contingencies

We and our subsidiaries are parties to various legal, regulatory and other matters arising from the day-to-day operations of our businesses or certain predecessor operations that may result in claims against the Company. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves and insurance, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or dividends to our shareholders. We believe we have meritorious defenses to the matters to which we are a party and intend to vigorously defend the Company. When we determine a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such contingencies based on our best estimate using information available at that time. If the estimated loss is a range of potential outcomes and there is no better estimate within the range, we accrue the amount at the low end of the range. We disclose contingencies where an adverse outcome may be material, or in the judgment of management, we conclude the matter should otherwise be disclosed.

Federal Energy Regulatory Commission Proceedings

SFPP

The tariffs and rates charged by SFPP are subject to a number of ongoing proceedings at the FERC, including the complaints and protests of various shippers the most recent of which was filed in late 2015 with the FERC (docketed at OR16-6) challenging SFPP’s filed East Line rates. In general, these complaints and protests allege the rates and tariffs charged by SFPP are not just and reasonable under the Interstate Commerce Act (ICA). In some of these proceedings shippers have challenged the overall rate being charged by SFPP, and in others the shippers have challenged SFPP's index-based rate increases. If the shippers prevail on their arguments or claims, they are entitled to seek reparations (which may reach back up to two years prior to the filing date of their complaints) or refunds of any excess rates paid, and SFPP may be required to reduce its rates going forward. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts. The issues involved in these proceedings include, among others, whether indexed rate increases are justified, and the appropriate level of return and income tax allowance SFPP may include in its rates. On March 22, 2016, the D.C. Circuit issued a decision in United Airlines, Inc. v. FERC remanding to FERC for further consideration of two issues: (1) the appropriate data to be used to determine the return on equity for SFPP in the underlying docket, and (2) the just and reasonable return to be provided to a tax pass-through entity that includes an income tax allowance in its underlying cost of service. With respect to the various SFPP related complaints and protest proceedings at the FERC, we estimate that the shippers are seeking approximately $40 million in annual rate reductions and approximately $200 million in refunds. Management believes SFPP has meritorious arguments supporting SFPP's rates and intends to vigorously defend SFPP against these complaints and protests. However, to the extent the shippers are successful in one or more of the complaints or protest proceedings, SFPP estimates that applying the principles of FERC precedent, as applicable, to pending SFPP cases would result in rate reductions and refunds substantially lower than those sought by the shippers.

EPNG

The tariffs and rates charged by EPNG are subject to two ongoing FERC proceedings (the "2008 rate case" and the "2010 rate case"). With respect to the 2008 rate case, the FERC issued its decision (Opinion 517-A) in July 2015. The FERC generally upheld its prior determinations, ordered refunds to be paid within 60 days, and stated that it will apply its findings in Opinion 517-A to the same issues in the 2010 rate case. EPNG has sought federal appellate review of Opinion 517-A and oral arguments were held on February 15, 2017. On February 21, 2017, the reviewing court delayed the case until FERC rules on the rehearing requests pending in the 2010 Rate Case. With respect to the 2010 rate case, the FERC issued its decision (Opinion 528-A) on February 18, 2016. The FERC generally upheld its prior determinations, affirmed prior findings of an Administrative Law Judge that certain shippers qualify for lower rates, and required EPNG to file revised pro forma recalculated rates consistent with the terms of Opinions 517-A and 528-A. EPNG and two intervenors sought rehearing of certain aspects of the decision, and the judicial review sought by certain intervenors has been delayed until the FERC issues an order on rehearing. All refund obligations related to the 2008 rate case were satisfied during calendar year 2015. With respect to the 2010 rate case, EPNG believes it has an appropriate reserve related to the findings in Opinions 517-A and 528-A.

NGPL and WIC

On January 19, 2017, NGPL and WIC were notified by the FERC of rate proceedings against them pursuant to section 5 of the Natural Gas Act (the "Orders"). Each respective proceeding will set the matter for hearing and determine whether NGPL's and WIC's current rates remain just and reasonable. A proceeding under section 5 of the Natural Gas Act is prospective in nature such that a change in rates charged to customers, if any, would likely only occur after the FERC has issued a final order. Unless a settlement is reached sooner, an initial Administrative Law Judge decision is anticipated in late February, 2018, with a final FERC decision anticipated by the third quarter, 2018. We do not believe that the ultimate resolution of these proceedings will have a material adverse impact on our results of operations or cash flows from operations.

Other Commercial Matters

Union Pacific Railroad Company Easements & Related Litigation

SFPP and Union Pacific Railroad Company (UPRR) are engaged in a proceeding to determine the extent, if any, to which the rent payable by SFPP for the use of pipeline easements on rights-of-way held by UPRR should be adjusted pursuant to existing contractual arrangements for the ten-year period beginning January 1, 2004 (Union Pacific Railroad Company v. Santa Fe Pacific Pipelines, Inc., SFPP, L.P., Kinder Morgan Operating L.P. "D", Kinder Morgan G.P., Inc., et al., Superior Court of the State of California for the County of Los Angeles, filed July 28, 2004). In September 2011, the trial judge determined that the annual rent payable as of January 1, 2004 was $14 million, subject to annual consumer price index increases. SFPP appealed the judgment.

By notice dated October 25, 2013, UPRR demanded the payment of $22.3 million in rent for the first year of the next ten-year period beginning January 1, 2014, which SFPP rejected.

On November 5, 2014, the Court of Appeals issued an opinion which reversed the judgment, including the award of prejudgment interest, and remanded the matter to the trial court for a determination of UPRR's property interest in its right-of-way, including whether UPRR has sufficient interest to grant SFPP's easements. UPRR filed a petition for review to the California Supreme Court which was denied. The trial court is expected to retry the 2004 rental dispute in April, 2018. Until the 2004 rental dispute is resolved, the parties have stayed the proceeding to establish rent for the rental term beginning in 2014.

After the above-referenced decision by the California Court of Appeals which held that UPRR does not own the subsurface rights to grant certain easements and may not be able to collect rent from those easements, a purported class action lawsuit was filed in 2015 in the U.S. District Court for the Southern District of California by private landowners in California who claim to be the lawful owners of subsurface real property allegedly used or occupied by UPRR or SFPP. Substantially similar follow-on lawsuits were filed and are pending in federal courts by landowners in Nevada, Arizona and New Mexico. These suits, which are brought purportedly as class actions on behalf of all landowners who own land in fee adjacent to and underlying the railroad easement under which the SFPP pipeline is located in those respective states, assert claims against UPRR, SFPP, KMGP, and

Kinder Morgan Operating L.P. "D" for declaratory judgment, trespass, ejectment, quiet title, unjust enrichment, accounting, and alleged unlawful business acts and practices arising from defendants' alleged improper use or occupation of subsurface real property. On April 19, 2017, the federal district court in Arizona denied plaintiffs' motion for class certification. SFPP views these cases as primarily a dispute between UPRR and the plaintiffs. UPRR purported to grant SFPP a network of subsurface pipeline easements along UPRR's railroad right-of-way. SFPP relied on the validity of those easements and paid rent to UPRR for the value of those easements. We believe we have recorded a right-of-way liability sufficient to cover our potential obligation, if any, for back rent.

SFPP and UPRR have engaged in multiple disputes over the circumstances under which SFPP must pay for relocations of its pipeline within the UPRR right-of-way and the safety standards that govern relocations. In 2006, following a bench trial regarding the circumstances under which SFPP must pay for relocations, the judge determined that SFPP must pay for any relocations resulting from any legitimate business purpose of the UPRR. The decision was affirmed on appeal. In addition, UPRR contends that SFPP must comply with the more expensive American Railway Engineering and Maintenance-of-Way Association (AREMA) standards in determining when relocations are necessary and in completing relocations. Each party has sought declaratory relief with respect to its positions regarding the application of these standards with respect to relocations. In 2011, a jury verdict was reached that SFPP was obligated to comply with AREMA standards in connection with a railroad project in Beaumont Hills, California. In 2014, the trial court entered judgment against SFPP, consistent with the jury's verdict. On June 29, 2015, the parties entered into a confidential settlement of all of the claims relating to the project in Beaumont Hills and the case was dismissed.

Since SFPP does not know UPRR's plans for projects or other activities that would cause pipeline relocations, it is difficult to quantify the effects of the outcome of these cases on SFPP. Even if SFPP is successful in advancing its positions, significant relocations for which SFPP must nonetheless bear the cost (i.e., for railroad purposes, with the standards in the federal Pipeline Safety Act applying) could have an adverse effect on our financial position, results of operations, cash flows, and our dividends to our shareholders. These effects could be even greater in the event SFPP is unsuccessful in one or more of these lawsuits.

Gulf LNG Facility Arbitration

On March 1, 2016, Gulf LNG Energy, LLC and Gulf LNG Pipeline, LLC (GLNG) received a Notice of Disagreement and Disputed Statements and a Notice of Arbitration from Eni USA Gas Marketing LLC (Eni USA), one of two companies that entered into a terminal use agreement for capacity of the Gulf LNG Facility in Mississippi for an initial term that is not scheduled to expire until the year 2031. Eni USA is an indirect subsidiary of Eni S.p.A., a multi-national integrated energy company headquartered in Milan, Italy. Pursuant to its Notice of Arbitration, Eni USA seeks declaratory and monetary relief based upon its assertion that (i) the terminal use agreement should be terminated because changes in the U.S. natural gas market since the execution of the agreement in December 2007 have "frustrated the essential purpose" of the agreement and (ii) activities allegedly undertaken by affiliates of Gulf LNG Holdings Group LLC "in connection with a plan to convert the LNG Facility into a liquefaction/export facility have given rise to a contractual right on the part of Eni USA to terminate" the agreement. As set forth in the terminal use agreement, disputes are meant to be resolved by final and binding arbitration. A three-member arbitration panel conducted an arbitration hearing in January 2017. We expect the arbitration panel will issue its decision within approximately four months. Eni USA has indicated that it will continue to pay the amounts claimed to be due pending resolution of the dispute. The successful assertion by Eni USA of its claim to terminate or amend its payment obligations under the agreement prior to the expiration of its initial term could have an adverse effect on the business, financial position, results of operations, or cash flows of GLNG and distributions to KMI, a 50% shareholder of GLNG. We view the demand for arbitration to be without merit, and we will continue to contest it vigorously.

Brinckerhoff v. El Paso Pipeline GP Company, LLC., et al.

In December 2011 (Brinckerhoff I), March 2012, (Brinckerhoff II), May 2013 (Brinckerhoff III) and June 2014 (Brinckerhoff IV), derivative lawsuits were filed in Delaware Chancery Court against El Paso Corporation, El Paso Pipeline GP Company, L.L.C., the general partner of EPB, and the directors of the general partner at the time of the relevant transactions. EPB was named in these lawsuits as a “Nominal Defendant.” The lawsuits arose from the March 2010, November 2010, May 2012 and June 2011 drop-down transactions involving EPB’s purchase of SLNG, Elba Express, CPG and interests in SNG and CIG. The lawsuits alleged various conflicts of interest and that the consideration paid by EPB was excessive. Brinckerhoff I and II were consolidated into one proceeding. Motions to dismiss were filed in Brinckerhoff III and Brinckerhoff IV. On June 12, 2014, defendants’ motion for summary judgment was granted in Brinckerhoff I, dismissing the case in its entirety. Defendants’ motion for summary judgment in Brinckerhoff II was granted in part, dismissing certain claims and allowing the matter to go to trial in late 2014 on the remaining claims. On April 20, 2015, the Court issued a post-trial memorandum opinion (Memorandum Opinion) in Brinckerhoff II entering judgment in favor of all of the defendants other than the general partner of

EPB, but finding the general partner liable for breach of contract in connection with EPB's purchase of 49% interests in Elba and SLNG and a 15% interest in SNG in a $1.13 billion drop-down transaction that closed on November 19, 2010 (Fall Dropdown), prior to our acquisition of El Paso Corporation in 2012. In its Memorandum Opinion, the Court determined that EPB suffered damages of $171 million from the Fall Dropdown, which the Court determined to be the amount that EPB overpaid for Elba. Based on this ruling, the Court entered judgment on February 4, 2016 in the amount of $100.2 million plus interest at the legal rate for the period from November 15, 2010 until the date of payment. We filed an appeal to the Delaware Supreme Court and Brinckerhoff filed a cross-appeal challenging the dismissal of Brinckerhoff I. On December 20, 2016, the Delaware Supreme Court issued an opinion reversing the trial court's December 2, 2015 decision, finding that the claims were derivative in nature and that Brinckerhoff lost standing to continue both the appeal and cross-appeal when the merger closed. Because its holding terminates the litigation, the Supreme Court did not reach the other issues raised by the parties. On January 5, 2017, the Supreme Court issued a mandate to the trial court reversing the February 4, 2016 judgment in its entirety. On January 30, 2017, the trial court dismissed the case. After the filing of an agreed stipulation and order of dismissal, the remaining lawsuits (Brinckerhoff III and IV) were dismissed by the Chancery Court on March 2, 2017, thereby successfully terminating all remaining litigation involving the drop down transactions.

Price Reporting Litigation

Beginning in 2003, several lawsuits were filed by purchasers of natural gas against El Paso Corporation, El Paso Marketing L.P. and numerous other energy companies based on a claim under state antitrust law that such defendants conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. Several of the cases have been settled or dismissed. The remaining cases, which are pending in Nevada federal district court, were dismissed, but the dismissal was reversed by the 9th Circuit Court of Appeals. The U.S. Supreme Court affirmed the 9th Circuit Court of Appeals in a decision dated April 21, 2015, and the cases were then remanded to the Nevada federal district court for further consideration and trial, if necessary, of numerous remaining issues. On May 24, 2016, the district court granted a motion for summary judgment dismissing a lawsuit brought by an industrial consumer in Kansas in which approximately $500 million in damages has been alleged. That ruling has been appealed to the 9th Circuit Court of Appeals. Tentative settlements have been reached in class actions originally filed in Kansas and Missouri, which settlements are subject to court approval. In the remaining case, a Wisconsin class action in which approximately $300 million in damages has been alleged against all defendants, the district court denied plaintiff's motion for class certification. Plaintiff has petitioned the 9th Circuit Court of Appeals for an interlocutory review of this ruling. There remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, which may be allocated to us in the remaining lawsuits and therefore, our legal exposure, if any, and costs are not currently determinable.

Pipeline Integrity and Releases

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

General

As of March 31, 2017 and December 31, 2016, our total reserve for legal matters was $413 million and $407 million, respectively. The reserve primarily relates to various claims from regulatory proceedings arising in our products and natural gas pipeline segments.

Environmental Matters

We and our subsidiaries are subject to environmental cleanup and enforcement actions from time to time. In particular, CERCLA generally imposes joint and several liability for cleanup and enforcement costs on current and predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct, subject to the right of a liable party to establish a “reasonable basis” for apportionment of costs. Our operations are also subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in pipeline, terminal and CO_2 field and oil field operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies under the terms of authority of those laws, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

We are currently involved in several governmental proceedings involving alleged violations of environmental and safety regulations, including alleged violations of the Risk Management Program and leak detection and repair requirements of the Clean Air Act. As we receive notices of non-compliance, we attempt to negotiate and settle such matters where appropriate. These alleged violations may result in fines and penalties, but we do not believe any such fines and penalties, individually or in the aggregate, will be material. We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under administrative orders or related state remediation programs. We have established a reserve to address the costs associated with the cleanup.

In addition, we are involved with and have been identified as a potentially responsible party in several federal and state superfund sites. Environmental reserves have been established for those sites where our contribution is probable and reasonably estimable. In addition, we are from time to time involved in civil proceedings relating to damages alleged to have occurred as a result of accidental leaks or spills of refined petroleum products, NGL, natural gas and CO_2.

Portland Harbor Superfund Site, Willamette River, Portland, Oregon

In December 2000, the EPA issued General Notice letters to potentially responsible parties including GATX Terminals Corporation (n/k/a KMLT). At that time, GATX owned two liquids terminals along the lower reach of the Willamette River, an industrialized area known as Portland Harbor. Portland Harbor is listed on the National Priorities List and is designated as a Superfund Site under CERCLA. A group of potentially responsible parties formed what is known as the Lower Willamette Group (LWG), of which KMLT is a non-voting member and pays a minimal fee to be part of the group. The LWG agreed to conduct the remedial investigation and feasibility study (RI/FS) leading to the proposed remedy for cleanup of the Portland Harbor site. After a dispute with the EPA concerning certain provision of the FS, the parties agreed that the EPA would complete the FS and that the LWG may dispute the FS within 14 days of the publication of the proposed remedy for cleanup. EPA issued the FS and the Proposed Plan on June 8, 2016. The EPA's Proposed Plan included a combination of dredging, capping, and enhanced natural recovery. Comments on the FS and the Proposed Plan were submitted by the LWG and on our own behalf on September 7, 2016. On January 6, 2017, the EPA issued its Record of Decision (ROD) for the final cleanup plan. The final remedy is more stringent than the remedy proposed in the EPA's Proposed Plan. The estimated cost has increased from approximately $750 million to approximately $1.1 billion and active cleanup is now expected to take as long as 13 years to complete. KMLT and 90 other parties are involved in a non-judicial allocation process to determine each party's respective share of the cleanup costs. We are participating in the allocation process on behalf of KMLT and KMBT in connection with their current or former ownership or operation of four facilities located in Portland Harbor. Our share of responsibility for Portland Harbor Superfund Site costs will not be determined until the ongoing non-judicial allocation process is concluded in several years or a lawsuit is filed that results in a judicial decision allocating responsibility. Until the allocation process is completed, we are unable to reasonably estimate the extent of our liability for the costs related to the design of the proposed remedy and cleanup of the site.

Roosevelt Irrigation District v. Kinder Morgan G.P., Inc., Kinder Morgan Energy Partners, L.P. , U.S. District Court, Arizona

The Roosevelt Irrigation District sued KMGP, KMEP and others under CERCLA for alleged contamination of the water purveyor's wells. The First Amended Complaint sought $175 million in damages from approximately 70 defendants. On August 6, 2013 plaintiffs filed their Second Amended Complaint seeking monetary damages in unspecified amounts and reducing the number of defendants to 26 including KMEP and SFPP. The claims now presented against KMEP and SFPP are related to alleged releases from a specific parcel within the SFPP Phoenix Terminal and the alleged impact of such releases on water wells owned by the plaintiffs and located in the vicinity of the Terminal. We have filed an answer, general denial, and affirmative defenses in response to the Second Amended Complaint and fact discovery is proceeding.

Uranium Mines in Vicinity of Cameron, Arizona

In the 1950s and 1960s, Rare Metals Inc., a historical subsidiary of EPNG, mined approximately twenty uranium mines in the vicinity of Cameron, Arizona, many of which are located on the Navajo Indian Reservation. The mining activities were in response to numerous incentives provided to industry by the U.S. to locate and produce domestic sources of uranium to support the Cold War-era nuclear weapons program. In May 2012, EPNG received a general notice letter from the EPA notifying EPNG of the EPA’s investigation of certain sites and its determination that the EPA considers EPNG to be a potentially responsible party within the meaning of CERCLA. In August 2013, EPNG and the EPA entered into an Administrative Order on Consent and Scope of Work pursuant to which EPNG is conducting a radiological assessment of the surface of the mines. On September 3, 2014, EPNG filed a complaint in the U.S. District Court for the District of Arizona (Case No. 3:14-08165-DGC) seeking cost recovery and contribution from the applicable federal government agencies toward the cost of environmental activities associated with the mines, given the pervasive control of such federal agencies over all aspects of the nuclear weapons program. Defendants filed an answer and counterclaims seeking contribution and recovery of response costs allegedly incurred by the federal agencies in investigating uranium impacts on the Navajo Reservation. The counterclaim of defendant EPA has been settled, and no viable claims for reimbursement by the other defendants are known to exist.

Lower Passaic River Study Area of the Diamond Alkali Superfund Site, Essex, Hudson, Bergen and Passaic Counties, New Jersey

EPEC Polymers, Inc. (EPEC Polymers) and EPEC Oil Company Liquidating Trust (EPEC Oil Trust), former El Paso Corporation entities now owned by KMI, are involved in an administrative action under CERCLA known as the Lower Passaic River Study Area Superfund Site (Site) concerning the lower 17-mile stretch of the Passaic River. It has been alleged that EPEC Polymers and EPEC Oil Trust may be potentially responsible parties (PRPs) under CERCLA based on prior ownership and/or operation of properties located along the relevant section of the Passaic River. EPEC Polymers and EPEC Oil Trust entered into two Administrative Orders on Consent (AOCs) which obligate them to investigate and characterize contamination at the Site. They are also part of a joint defense group of approximately 70 cooperating parties, referred to as the Cooperating Parties Group (CPG), which has entered into AOCs and is directing and funding the work required by the EPA. Under the first AOC, draft remedial investigation and feasibility studies (RI/FS) of the Site were submitted to the EPA in 2015, and comments from the EPA remain pending. Under the second AOC, the CPG members conducted a CERCLA removal action at the Passaic River Mile 10.9, and the group is currently conducting EPA-directed post-remedy monitoring in the removal area. We have established a reserve for the anticipated cost of compliance with the AOCs.

On April 11, 2014, the EPA announced the issuance of its Focused Feasibility Study (FFS) for the lower eight miles of the Passaic River Study Area, and its proposed plan for remedial alternatives to address the dioxin sediment contamination from the mouth of Newark Bay to River Mile 8.3. The EPA estimates the cost for the alternatives will range from $365 million to $3.2 billion. The EPA’s preferred alternative would involve dredging the river bank-to-bank and installing an engineered cap at an estimated cost of $1.7 billion. On March 4, 2016, the EPA issued its ROD for the lower 8.3 miles of the Passaic River Study area. The final cleanup plan in the ROD is substantially similar to the EPA’s preferred alternative announced on April 11, 2014. On October 5, 2016, the EPA entered into an AOC with one member of the PRP group requiring such member to spend $165 million to perform engineering and design work necessary to begin the cleanup of the lower 8.3 miles of the Passaic River. The design work is expected to take four years to complete and the cleanup is expected to take six years to complete.

In addition to the AOC with one member of the PRP group described above, the EPA has notified over 80 other PRPs, including EPEC Polymers and EPEC Oil Trust (the Notice), that the EPA intends to pursue additional agreements with other “major PRPs” and initiate negotiations over cash buyouts with parties whom the EPA does not consider “major PRPs.” The Notice creates significant uncertainty as to the implementation and associated costs of the remedy set forth in the FFS and ROD, and provides no guidance as to the EPA’s definition of a “major PRP” or the potential amount or range of cash buyouts. There is also uncertainty as to the impact of the RI/FS that the CPG is currently preparing for portions of the Site. The draft RI/FS was submitted by the CPG earlier in 2015 and proposes a different remedy than the FFS announced by the EPA. Therefore, the scope of potential EPA claims for the lower eight miles of the Passaic River is not reasonably estimable at this time.

Southeast Louisiana Flood Protection Litigation

On July 24, 2013, the Board of Commissioners of the Southeast Louisiana Flood Protection Authority - East (SLFPA) filed a petition for damages and injunctive relief in state district court for Orleans Parish, Louisiana (Case No. 13-6911) against TGP, SNG and approximately 100 other energy companies, alleging that defendants’ drilling, dredging, pipeline and industrial operations since the 1930’s have caused direct land loss and increased erosion and submergence resulting in alleged increased storm surge risk, increased flood protection costs and unspecified damages to the plaintiff. The SLFPA asserts claims for negligence, strict liability, public nuisance, private nuisance, and breach of contract. Among other relief, the petition seeks unspecified monetary damages, attorney fees, interest, and injunctive relief in the form of abatement and restoration of the alleged coastal land loss including but not limited to backfilling and re-vegetation of canals, wetlands and reef creation, land bridge construction, hydrologic restoration, shoreline protection, structural protection, and bank stabilization. On August 13, 2013, the suit was removed to the U.S. District Court for the Eastern District of Louisiana. On February 13, 2015, the Court granted defendants' motion to dismiss the suit for failure to state a claim, and issued an order dismissing the SLFPA's claims with prejudice. On March 3, 2017, the U.S. Court of Appeals for the Fifth Circuit affirmed the U.S. District Court's decision. On March 17, 2017, the SLFPA filed a petition seeking en banc review and reconsideration of the decision by the Fifth Circuit, and such petition was denied.

Plaquemines Parish Louisiana Coastal Zone Litigation

On November 8, 2013, the Parish of Plaquemines, Louisiana filed a petition for damages in the state district court for Plaquemines Parish, Louisiana (Docket No. 60-999) against TGP and 17 other energy companies, alleging that defendants' oil and gas exploration, production and transportation operations in the Bastian Bay, Buras, Empire and Fort Jackson oil and gas fields of Plaquemines Parish caused substantial damage to the coastal waters and nearby lands (Coastal Zone) within the Parish, including the erosion of marshes and the discharge of oil waste and other pollutants which detrimentally affected the quality of state waters and plant and animal life, in violation of the State and Local Coastal Resources Management Act of 1978 (Coastal Zone Management Act). As a result of such alleged violations of the Coastal Zone Management Act, Plaquemines Parish seeks, among other relief, unspecified monetary relief, attorney fees, interest, and payment of costs necessary to restore the allegedly affected Coastal Zone to its original condition, including costs to clear, vegetate and detoxify the Coastal Zone. In connection with this suit, TGP has made two tenders for defense and indemnity: (1) to Anadarko, as successor to the entity that purchased TGP's oil and gas assets in Bastian Bay, and (2) to Kinetica, which purchased TGP's pipeline assets in Bastian Bay in 2013. Anadarko has accepted TGP's tender (limited to oil and gas assets), and Kinetica rejected TGP's tender. TGP responded to Kinetica by reasserting TGP's demand for defense and indemnity and reserving its rights. On November 12, 2015, the Plaquemines Parish Council adopted a resolution directing its legal counsel in all its Coastal Zone cases to take all actions necessary to cause the dismissal of all such cases. On April 14, 2016, following interventions in the suit by the Louisiana Department of Natural Resources and Attorney General, the Parish Council passed a resolution rescinding its November 12, 2015 resolution that had directed its counsel to dismiss the suit. We intend to continue to vigorously defend the suit.

Vermilion Parish Louisiana Coastal Zone Litigation

On July 28, 2016, the District Attorney for the 15th Judicial District of Louisiana, purporting to act on behalf of Vermilion Parish and the State of Louisiana, filed suit in the state district court for Vermilion Parish, Louisiana against TGP and 52 other energy companies, alleging that the defendants' oil and gas and transportation operations associated with the development of several fields in Vermilion Parish (Operational Areas) were conducted in violation of the Coastal Zone Management Act. The suit alleges such operations caused substantial damage to the coastal waters and nearby lands (Coastal Zone) of Vermilion Parish, resulting in the release of pollutants and contaminants into the environment, improper discharge of oil field wastes, the improper use of waste pits and failure to close such pits, and the dredging of canals, which resulted in degradation of the Operational Areas, including erosion of marshes and degradation of terrestrial and aquatic life therein. As a result of such alleged violations of the Coastal Zone Management Act, the suit seeks a judgment against the defendants awarding all appropriate damages, the payment of costs to clear, revegetate, detoxify and otherwise restore the Vermilion Parish Coastal Zone, actual restoration of the affected Coastal Zone to its original condition, and reasonable costs and attorney fees. On September 2, 2016, the case was removed to the United States District Court for the Western District of Louisiana. Plaintiffs filed a motion to remand the case to the state district court, and such motion remains pending.

Vintage Assets, Inc. Coastal Erosion Litigation

On December 18, 2015, Vintage Assets, Inc. filed a petition in the 25th Judicial District Court for Plaquemines Parish, Louisiana alleging that its 5,000 acre property is composed of coastal wetlands, and that SNG and TGP failed to maintain pipeline canals and banks, causing widening of the canals, land loss, and damage to the ecology and hydrology of the marsh, in breach of right of way agreements, prudent operating practices, and Louisiana law. The suit also claims that defendants' alleged failure to maintain pipeline canals and banks constitutes negligence and has resulted in encroachment of the canals, constituting trespass. The suit seeks in excess of $80 million in money damages, including recovery of litigation costs, damages for trespass, and money damages associated with an alleged loss of natural resources and projected reconstruction cost of replacing or restoring wetlands. The suit was removed to the U.S. District Court for the Eastern District of Louisiana. The SNG assets at issue were sold to Highpoint Gas Transmission, LLC in 2011, which was subsequently purchased by American Midstream Partners, LP. In response to

SNG's demand for defense and indemnity, American Midstream Partners agreed to pay 50% of joint defense costs and expenses, with a percentage of indemnity to be determined upon final resolution of the suit. On October 20, 2016, plaintiffs filed an amended complaint naming Highpoint Gas Transmission, LLC as an additional defendant. A non-jury trial is scheduled to begin on September 11, 2017 and we intend to vigorously defend the suit.

General

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note, and other matters to which we and our subsidiaries are a party, will not have a material adverse effect on our business, financial position, results of operations or cash flows. As of March 31, 2017 and December 31, 2016, we have accrued a total reserve for environmental liabilities in the amount of $299 million and $302 million, respectively. In addition, as of both March 31, 2017 and December 31, 2016, we have recorded a receivable of $13 million, for expected cost recoveries that have been deemed probable.

10. Recent Accounting Pronouncements

Topic 606

On May 28, 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers” followed by a series of related accounting standard updates (collectively referred to as “Topic 606”). Topic 606 is designed to create greater revenue recognition and disclosure comparability in financial statements. The provisions of Topic 606 include a five-step process by which an entity will determine revenue recognition, depicting the transfer of goods or services to customers in amounts reflecting the payment to which an entity expects to be entitled in exchange for those goods or services. Topic 606 requires certain disclosures about contracts with customers and provides more comprehensive guidance for transactions such as service revenue, contract modifications, and multiple-element arrangements.

We are in the process of comparing our current revenue recognition policies to the requirements of Topic 606 for each of our revenue categories. While we have not identified any material differences in the amount and timing of revenue recognition for the categories we have reviewed to date, our evaluation is not complete, and we have not concluded on the overall impacts of adopting Topic 606. Topic 606 will require that our revenue recognition policy disclosure include further detail regarding our performance obligations as to the nature, amount, timing, and estimates of revenue and cash flows generated from our contracts with customers. Topic 606 will also require disclosure of significant changes in contract asset and contract liability balances period to period and the amount of the transaction price allocated to performance obligations that are unsatisfied (or partially unsatisfied) as of the end of the reporting period, as applicable. We will adopt Topic 606 effective January 1, 2018. Topic 606 provides for adoption either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. We plan to make a determination as to our method of adoption once we more fully complete our evaluation of the impacts of the standard on our revenue recognition and we are better able to evaluate the cost-benefit of each method.

ASU No. 2015-11

On July 22, 2015, the FASB issued ASU No. 2015-11, “Inventory (Topic 330): Simplifying the Measurement of Inventory.” This ASU requires entities to subsequently measure inventory at the lower of cost and net realizable value, and defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. ASU No. 2015-11 was effective January 1, 2017. We adopted ASU No. 2015-11 with no material impact to our financial statements.

ASU No. 2016-02

On February 25, 2016, the FASB issued ASU 2016-02, “Leases (Topic 842).” This ASU requires that lessees will be required to recognize assets and liabilities on the balance sheet for the present value of the rights and obligations created by all leases with terms of more than 12 months. The ASU also will require disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. ASU 2016-02 will be effective for us as of January 1, 2019. We are currently reviewing the effect of ASU No. 2016-02.

ASU No. 2016-09

On March 30, 2016, the FASB issued ASU 2016-09, “Compensation - Stock Compensation (Topic 718).” This ASU was issued as part of the FASB’s simplification initiative and affects all entities that issue share-based payment awards to their employees. This ASU covers accounting for income taxes, forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. ASU No. 2016-09 was effective January 1, 2017.

We adopted ASU No. 2016-09 with no material impact to our financial statements. See Note 8.

ASU No. 2016-13

On June 16, 2016, the FASB issued ASU 2016-13, “Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments.” This ASU modifies the impairment model to utilize an expected loss methodology in place of the currently used incurred loss methodology, which will result in the more timely recognition of losses. ASU No. 2016-13 will be effective for us as of January 1, 2020. We are currently reviewing the effect of ASU No. 2016-13.

ASU No. 2016-18

On November 17, 2016, the FASB issued ASU 2016-18, “Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force).” This ASU requires the statement of cash flows to explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents are to be included with cash and cash equivalents when reconciling the beginning of period and end of period amounts shown on the statement of cash flows. ASU No. 2016-18 will be effective for us as of January 1, 2018. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2017-04

On January 26, 2017, the FASB issued ASU 2017-04, “Simplifying the Test for Goodwill Impairment (Topic 350)” to simplify the accounting for goodwill impairment. The guidance removes Step 2 of the goodwill impairment test, which requires a hypothetical purchase price allocation. A goodwill impairment will now be the amount by which a reporting unit’s carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. ASU No. 2017-04 will be effective for us as of January 1, 2020. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2017-05

On February 22, 2017, the FASB issued ASU No. 2017-05, “Other Income-Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets.” This ASU clarifies the scope and accounting of a financial asset that meets the definition of an “in-substance nonfinancial asset” and defines the term “in-substance nonfinancial asset.” This ASU also adds guidance for partial sales of nonfinancial assets. ASU 2017-05 will be effective at the same time Topic 606, Revenue from Contracts with Customers, is effective. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2017-07

On March 10, 2017, the FASB issued ASU 2017-07, “Compensation - Retirement Benefits (Topic 715).” This ASU requires an employer to disaggregate the service cost component from the other components of net benefit cost, allow only the service cost component of net benefit cost to be eligible for capitalization, and how to present the service cost component and the other components of net benefit cost in the income statement. ASU No. 2017-07 will be effective for us as of January 1, 2018. We are currently reviewing the effect of this ASU to our financial statements.

11. Guarantee of Securities of Subsidiaries

KMI, along with its direct subsidiary KMP, are issuers of certain public debt securities. KMI, KMP and substantially all of KMI’s wholly owned domestic subsidiaries are parties to a cross guarantee agreement whereby each party to the agreement unconditionally guarantees, jointly and severally, the payment of specified indebtedness of each other party to the agreement. Accordingly, with the exception of certain subsidiaries identified as Subsidiary Non-Guarantors, the parent issuer, subsidiary issuer and other subsidiaries are all guarantors of each series of public debt. As a result of the cross guarantee agreement, a holder of any of the guaranteed public debt securities issued by KMI or KMP is in the same position with respect to the net assets, income and cash flows of KMI and the Subsidiary Issuer and Guarantors. The only amounts that are not available to the holders of each of the guaranteed public debt securities to satisfy the repayment of such securities are the net assets, income and cash flows of the Subsidiary Non-Guarantors.

In lieu of providing separate financial statements for subsidiary issuer and guarantor, we have included the accompanying condensed consolidating financial statements based on Rule 3-10 of the SEC's Regulation S-X. We have presented each of the parent and subsidiary issuer in separate columns in this single set of condensed consolidating financial statements.

On September 30, 2016, Copano (previously reflected as a Subsidiary Issuer and Guarantor) repaid the $332 million principal amount of its 7.125% senior notes due 2021. Copano continues to be a subsidiary guarantor under the cross guarantee agreement mentioned above. For all periods presented, financial statement balances and activities for Copano are now reflected within the Subsidiary Guarantor column, and the Subsidiary Issuer and Guarantor-Copano column has been eliminated.

On September 1, 2016, we sold a 50% equity interest in SNG. Subsequent to the transaction, we deconsolidated SNG and now account for our equity interest in SNG as an equity investment. Our wholly owned subsidiary which holds our interest in SNG is reflected within the Subsidiary Guarantors column of these condensed consolidating financial statements.

Excluding fair value adjustments, as of March 31, 2017, Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, and Subsidiary Guarantors had $14,252 million, $18,885 million, and $4,191 million, respectively, of Guaranteed Notes outstanding. Included in the Subsidiary Guarantors debt balance as presented in the accompanying March 31, 2017 condensed consolidating balance sheet is approximately $167 million of capital lease obligations that are not subject to the cross guarantee agreement.

The accounts within the Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, Subsidiary Guarantors and Subsidiary Non-Guarantors are presented using the equity method of accounting for investments in subsidiaries, including subsidiaries that are guarantors and non-guarantors, for purposes of these condensed consolidating financial statements only. These intercompany investments and related activities eliminate in consolidation and are presented separately in the accompanying condensed consolidating balance sheets and statements of income and cash flows.

A significant amount of each Issuers' income and cash flow is generated by its respective subsidiaries. As a result, the funds necessary to meet its debt service and/or guarantee obligations are provided in large part by distributions or advances it receives from its respective subsidiaries. We utilize a centralized cash pooling program among our majority-owned and consolidated subsidiaries, including the Subsidiary Issuers and Guarantors and Subsidiary Non-Guarantors. The following Condensed Consolidating Statements of Cash Flows present the intercompany loan and distribution activity, as well as cash collection and payments made on behalf of our subsidiaries, as cash activities.

Condensed Consolidating Statements of Income and Comprehensive Income
for the Three Months Ended March 31, 2017
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 9	$ —	$ 3,058	$ 375	$ (18)	$ 3,424
Operating Costs, Expenses and Other						
Costs of sales	—	—	1,017	71	(7)	1,081
Depreciation, depletion and amortization	4	—	476	78	—	558
Other operating expenses	15	—	668	133	(11)	805
Total Operating Costs, Expenses and Other	19	—	2,161	282	(18)	2,444
Operating (loss) income	(10)	—	897	93	—	980
Other Income (Expense)						
Earnings from consolidated subsidiaries	846	831	102	18	(1,797)	—
Earnings from equity investments	—	—	175	—	—	175
Interest, net	(177)	6	(282)	(12)	—	(465)
Amortization of excess cost of equity investments and other, net	—	—	(3)	4	—	1
Income Before Income Taxes	659	837	889	103	(1,797)	691
Income Tax Expense	(219)	(2)	(17)	(8)	—	(246)
Net Income	440	835	872	95	(1,797)	445
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(5)	(5)
Net Income Attributable to Controlling Interests	440	835	872	95	(1,802)	440
Preferred Stock Dividends	(39)	—	—	—	—	(39)
Net Income Available to Common Stockholders	$ 401	$ 835	$ 872	$ 95	$ (1,802)	$ 401
Net Income	$ 440	$ 835	$ 872	$ 95	$ (1,797)	$ 445
Total other comprehensive income	68	106	99	21	(226)	68
Comprehensive income	508	941	971	116	(2,023)	513
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(5)	(5)
Comprehensive income attributable to controlling interests	$ 508	$ 941	$ 971	$ 116	$ (2,028)	$ 508

Condensed Consolidating Statements of Income and Comprehensive Income
for the Three Months Ended March 31, 2016
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor-KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 9	$ —	$ 2,825	$ 370	$ (9)	$ 3,195
Operating Costs, Expenses and Other						
Costs of sales	—	—	652	76	3	731
Depreciation, depletion and amortization	5	—	464	82	—	551
Other operating expenses	19	2	816	272	(12)	1,097
Total Operating Costs, Expenses and Other	24	2	1,932	430	(9)	2,379
Operating (loss) income	(15)	(2)	893	(60)	—	816
Other Income (Expense)						
Earnings from consolidated subsidiaries	658	597	23	14	(1,292)	—
Earnings from equity investments	—	—	94	—	—	94
Interest, net	(170)	63	(321)	(13)	—	(441)
Amortization of excess cost of equity investments and other, net	—	—	(5)	4	—	(1)
Income (Loss) Before Income Taxes	473	658	684	(55)	(1,292)	468
Income Tax (Expense) Benefit	(158)	(2)	6	—	—	(154)
Net Income (Loss)	315	656	690	(55)	(1,292)	314
Net Loss Attributable to Noncontrolling Interests	—	—	—	—	1	1
Net Income (Loss) Attributable to Controlling Interests	315	656	690	(55)	(1,291)	315
Preferred Stock Dividends	(39)	—	—	—	—	(39)
Net Income (Loss) Available to Common Stockholders	276	656	690	(55)	(1,291)	276
Net Income (Loss)	$ 315	$ 656	$ 690	$ (55)	$ (1,292)	$ 314
Total other comprehensive income (loss)	47	52	(6)	124	(170)	47
Comprehensive income	362	708	684	69	(1,462)	361
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	1	1
Comprehensive income attributable to controlling interests	$ 362	$ 708	$ 684	$ 69	$ (1,461)	$ 362

Condensed Consolidating Balance Sheets as of March 31, 2017
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS						
Cash and cash equivalents	$ 173	$ —	$ 11	$ 212	$ —	$ 396
Other current assets - affiliates	7,778	3,176	14,347	683	(25,984)	—
All other current assets	255	106	1,712	210	(4)	2,279
Property, plant and equipment, net	256	—	30,628	8,139	—	39,023
Investments	665	—	6,345	126	—	7,136
Investments in subsidiaries	26,944	28,921	4,609	4,025	(64,499)	—
Goodwill	13,789	22	5,168	3,175	—	22,154
Notes receivable from affiliates	754	21,597	1,069	459	(23,879)	—
Deferred income taxes	6,389	—	—	—	(2,325)	4,064
Other non-current assets	76	174	4,370	121	—	4,741
Total assets	$ 57,079	$ 53,996	$ 68,259	$ 17,150	$ (116,691)	$ 79,793
LIABILITIES AND STOCKHOLDERS' EQUITY						
Liabilities						
Current portion of debt	$ 1,368	$ 975	$ 1,462	$ 123	$ —	$ 3,928
Other current liabilities - affiliates	4,963	14,694	5,731	596	(25,984)	—
All other current liabilities	363	160	1,825	417	(4)	2,761
Long-term debt	13,219	18,268	3,306	671	—	35,464
Notes payable to affiliates	1,768	448	20,496	1,167	(23,879)	—
Deferred income taxes	—	—	698	1,627	(2,325)	—
All other long-term liabilities and deferred credits	753	114	1,220	548	—	2,635
Total liabilities	22,434	34,659	34,738	5,149	(52,192)	44,788
Stockholders' equity						
Total KMI equity	34,645	19,337	33,521	12,001	(64,859)	34,645
Noncontrolling interests	—	—	—	—	360	360
Total stockholders' Equity	34,645	19,337	33,521	12,001	(64,499)	35,005
Total Liabilities and Stockholders' Equity	$ 57,079	$ 53,996	$ 68,259	$ 17,150	$ (116,691)	$ 79,793

Condensed Consolidating Balance Sheets as of December 31, 2016
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS						
Cash and cash equivalents	$ 471	$ —	$ 9	$ 205	$ (1)	$ 684
Other current assets - affiliates	5,739	1,999	13,207	655	(21,600)	—
All other current assets	269	139	1,935	205	(3)	2,545
Property, plant and equipment, net	242	—	30,795	7,668	—	38,705
Investments	665	2	6,236	124	—	7,027
Investments in subsidiaries	26,907	29,421	4,307	4,028	(64,663)	—
Goodwill	13,789	22	5,167	3,174	—	22,152
Notes receivable from affiliates	516	21,608	1,132	412	(23,668)	—
Deferred income taxes	6,647	—	—	—	(2,295)	4,352
Other non-current assets	72	206	4,455	107	—	4,840
Total assets	$ 55,317	$ 53,397	$ 67,243	$ 16,578	$ (112,230)	$ 80,305
LIABILITIES AND STOCKHOLDERS' EQUITY						
Liabilities						
Current portion of debt	$ 1,286	$ 600	$ 687	$ 123	$ —	$ 2,696
Other current liabilities - affiliates	3,551	13,299	4,197	553	(21,600)	—
All other current liabilities	432	362	2,016	422	(4)	3,228
Long-term debt	13,308	19,277	4,095	674	—	37,354
Notes payable to affiliates	1,533	448	20,520	1,167	(23,668)	—
Deferred income taxes	—	—	681	1,614	(2,295)	—
Other long-term liabilities and deferred credits	776	111	821	517	—	2,225
Total liabilities	20,886	34,097	33,017	5,070	(47,567)	45,503
Stockholders' equity						
Total KMI equity	34,431	19,300	34,226	11,508	(65,034)	34,431
Noncontrolling interests	—	—	—	—	371	371
Total stockholders' Equity	34,431	19,300	34,226	11,508	(64,663)	34,802
Total Liabilities and Stockholders' Equity	$ 55,317	$ 53,397	$ 67,243	$ 16,578	$ (112,230)	$ 80,305

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Condensed Consolidating Statements of Cash Flows for the Three Months Ended March 31, 2017
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor-KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	$ (862)	$ 820	$ 2,983	$ 231	$ (2,286)	$ 886
Cash flows from investing activities						
Acquisitions of assets and investments, net of cash acquired	—	—	(4)	—	—	(4)
Capital expenditures	(19)	—	(582)	(63)	—	(664)
Sales of property, plant and equipment, and other net assets, net of removal costs	5	—	45	21	—	71
Contributions to investments	(15)	—	(173)	(3)	—	(191)
Distributions from equity investments in excess of cumulative earnings	463	—	119	—	(444)	138
Funding (to) from affiliates	(1,678)	406	(1,823)	(213)	3,308	—
Other, net	—	10	—	3	—	13
Net cash (used in) provided by investing activities	(1,244)	416	(2,418)	(255)	2,864	(637)
Cash flows from financing activities						
Issuances of debt	1,517	—	—	—	—	1,517
Payments of debt	(1,517)	(600)	(2)	(3)	—	(2,122)
Debt issue costs	(1)	—	—	—	—	(1)
Cash dividends - common shares	(280)	—	—	—	—	(280)
Cash dividends - preferred shares	(39)	—	—	—	—	(39)
Funding from affiliates	2,129	636	463	80	(3,308)	—
Contributions from investment partner	—	—	391	—	—	391
Contributions from parents	—	—	6	—	(6)	—
Contributions from noncontrolling interests	—	—	—	—	6	6
Distributions to parents	—	(1,272)	(1,421)	(47)	2,740	—
Distributions to noncontrolling interests	—	—	—	—	(9)	(9)
Other, net	(1)	—	—	—	—	(1)
Net cash provided by (used in) financing activities	1,808	(1,236)	(563)	30	(577)	(538)
Effect of exchange rate changes on cash and cash equivalents	—	—	—	1	—	1
Net (decrease) increase in cash and cash equivalents	(298)	—	2	7	1	(288)
Cash and cash equivalents, beginning of period	471	—	9	205	(1)	684
Cash and cash equivalents, end of period	$ 173	$ —	$ 11	$ 212	$ —	$ 396

Condensed Consolidating Statements of Cash Flows for the Three Months Ended March 31, 2016
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor-KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	$ (733)	$ 1,830	$ 2,144	$ 117	$ (2,308)	$ 1,050
Cash flows from investing activities						
Acquisitions of assets and investments, net of cash acquired	—	—	(330)	—	—	(330)
Capital expenditures	(24)	—	(340)	(447)	—	(811)
Sales of property, plant and equipment, and other net assets, net of removal costs	—	—	(6)	—	—	(6)
Contributions to investments	(31)	—	(10)	(3)	—	(44)
Distributions from equity investments in excess of cumulative earnings	790	—	29	—	(776)	43
Funding to affiliates	(1,360)	(759)	(842)	(123)	3,084	—
Other, net	—	(30)	36	(2)	—	4
Net cash used in investing activities	(625)	(789)	(1,463)	(575)	2,308	(1,144)
Cash flows from financing activities						
Issuances of debt	4,610	—	—	—	—	4,610
Payments of debt	(2,729)	(500)	(1,104)	(3)	—	(4,336)
Debt issue costs	(6)	—	—	—	—	(6)
Cash dividends - common shares	(279)	—	—	—	—	(279)
Cash dividends - preferred shares	(37)	—	—	—	—	(37)
Funding (to) from affiliates	(314)	881	2,084	433	(3,084)	—
Contributions from parents	—	—	—	87	(87)	—
Contributions from noncontrolling interests	—	—	—	—	87	87
Distributions to parents	—	(1,422)	(1,660)	(41)	3,123	—
Distributions to noncontrolling interests	—	—	—	—	(4)	(4)
Net cash provided by (used in) financing activities	1,245	(1,041)	(680)	476	35	35
Effect of exchange rate changes on cash and cash equivalents	—	—	—	5	—	5
Net (decrease) increase in cash and cash equivalents	(113)	—	1	23	35	(54)
Cash and cash equivalents, beginning of period	123	—	12	142	(48)	229
Cash and cash equivalents, end of period	$ 10	$ —	$ 13	$ 165	$ (13)	$ 175

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.
General and Basis of Presentation
The following discussion and analysis should be read in conjunction with our accompanying interim consolidated financial statements and related notes included elsewhere in this report, and in conjunction with (i) our consolidated financial statements and related notes and (ii) our management's discussion and analysis of financial condition and results of operations included in our 2016 Form 10-K.

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 three months ended March 31, 2016 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 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

	Three Months Ended March 31,			
	2017	2016	Earnings increase/(decrease)	
	(In millions, except percentages)			
Segment EBDA(a)				
Natural Gas Pipelines	$1,055	$994	$ 61	6 %
CO_2	218	187	31	17 %
Terminals	307	260	47	18 %
Products Pipelines	287	177	110	62 %
Kinder Morgan Canada	43	46	(3)	(7)%
Total Segment EBDA(b)	1,910	1,664	246	15 %
DD&A	(558)	(551)	(7)	(1)%
Amortization of excess cost of equity investments	(15)	(14)	(1)	(7)%
General and administrative and corporate charges(c)	(181)	(190)	9	5 %
Interest, net(d)	(465)	(441)	(24)	(5)%
Income before income taxes	691	468	223	48 %
Income tax expense	(246)	(154)	(92)	(60)%
Net income	445	314	131	42 %

Net (income) loss attributable to noncontrolling interests	(5)	1	(6)	(600)%
Net income attributable to Kinder Morgan, Inc.	440	315	125	40 %
Preferred Stock Dividends	(39)	(39)	—	— %
Net income available to common stockholders	$401	$276	$ 125	45 %

(a) Includes revenues, earnings from equity investments, and other, net, less operating expenses, other expense (income), net, 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) 2017 and 2016 amounts include a net increase (decrease) in earnings of $37 million and $(299) million, respectively, related to the combined 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) 2017 and 2016 amounts include net increases in expense of $7 million and $5 million, respectively, related to the combined effect of the certain items related to general and administrative expense and corporate charges disclosed below in "—General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests."

(d) 2017 and 2016 amounts include net decreases in expense of $12 million and $69 million, respectively, related to the combined effect of the certain items related to interest expense, net of unallocable interest income disclosed below in "—General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests."

The certain item totals reflected in footnotes (b), (c) and (d) to the table above accounted for $277 million of the increase in income before income taxes for the first quarter of 2017, as compared to the same prior year period (representing the difference between an increase of $42 million and a decrease of $235 million in income before income taxes for the first quarters of 2017 and 2016, respectively). After giving effect to these certain items, the remaining decrease of $54 million (8%) from the prior year quarter in income before income taxes is primarily attributable to decreased performance from our Natural Gas Pipelines business segment, largely associated with our sale of a 50% interest in SNG to The Southern Company on September 1, 2016, partially offset by increased performance from our Terminals business segment and decreased interest expense and general and administrative expense.

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

	Three Months Ended March 31,	
	2017	2016
	(In millions, except per share amounts)	
Net Income Available to Common Stockholders	$401	$276
Add/(Subtract):		
Certain items before book tax(a)	(42)	235
Book tax certain items(b)	12	(103)
Certain items after book tax	(30)	132
Noncontrolling interest certain items(c)	—	(6)
Net income available to common stockholders before certain items	371	402
Add/(Subtract):		
DD&A expense(d)	671	652
Total book taxes(e)	261	279
Cash taxes(f)	3	(2)
Other items(g)	13	10
Sustaining capital expenditures(h)	(104)	(108)
DCF	$1,215	$1,233
Weighted average common shares outstanding for dividends(i)	2,239	2,237
DCF per common share	$0.54	$0.55
Declared dividend per common share	$0.125	$0.125

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(a) Consists of certain items summarized in footnotes (b) through (d) to the "—Results of Operations—Consolidated Earnings Results" tables 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 and Corporate Charges, Interest, net and Noncontrolling Interests."

(b) Represents income tax provision on certain items, plus discrete income tax certain items.

(c) Represents noncontrolling interests share of certain items.

(d) Includes DD&A and amortization of excess cost of equity investments. 2017 and 2016 amounts also include $98 million and $87 million, respectively, of our share of equity investees' DD&A.

(e) Excludes book tax certain items. 2017 and 2016 amounts also include $27 million and $22 million, respectively, of our share of taxable equity investees' book tax expense.

(f) 2016 amount includes $(4) million of our share of taxable equity investees' cash taxes.

(g) Consists primarily of non-cash compensation associated with our restricted stock program.

(h) 2017 and 2016 amounts include $(18) million and $(22) million, respectively, of our share of equity investees' sustaining capital expenditures.

(i) Includes restricted stock awards that participate in common share dividends.

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Segment Earnings Results

Natural Gas Pipelines

	Three Months Ended March 31,	
	2017	2016
	(In millions, except operating statistics)	
Revenues(a)	$2,171	$1,971
Operating expenses	(1,272)	(939)
Loss on impairments and divestitures, net(b)	—	(116)
Earnings from equity investments(b)	146	72
Other, net	10	6
Segment EBDA(b)	1,055	994
Certain items(b)	(36)	138
Segment EBDA before certain items	$1,019	$1,132
Change from prior period	Increase/(Decrease)	
Revenues before certain items	$179	9 %
Segment EBDA before certain items	$(113)	(10)%
Natural gas transport volumes (BBtu/d)(c)	29,326	28,928
Natural gas sales volumes (BBtu/d)(c)	2,563	2,331
Natural gas gathering volumes (BBtu/d)(c)	2,712	3,207
Crude/condensate gathering volumes (MBbl/d)(c)	272	332

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Certain items affecting Segment EBDA

(a) 2017 amount includes an increase in revenue of $15 million, and 2016 amount includes a decrease in revenue of $6 million, related to non-cash mark-to-market derivative contracts used to hedge forecasted natural gas, NGL and crude oil sales.

(b) In addition to the revenue certain items described in footnote (a) above: 2017 amount also includes (i) an increase in earnings from equity investments of $22 million on the sale of a claim related to the early termination of a long-term natural gas transportation contract of an equity investee as a result of a customer bankruptcy proceeding; and (ii) a $1 million decrease in earnings from other certain items. 2016 amount also includes decreases in earnings of (i) $129 million related to losses on impairments and divestitures of assets primarily comprised of $106 million of project write-offs and $13 million related to an equity investment impairment; and (ii) $3 million from other certain items.

Other

(c) 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 the comparable three month periods ended March 31, 2017 and 2016:

Three months ended March 31, 2017 versus Three months ended March 31, 2016

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
SNG	$(83)	(72)%	$ (138)	(95)%
CIG	(15)	(18)%	(15)	(15)%
South Texas Midstream	(15)	(20)%	(3)	(1)%
KinderHawk	(7)	(28)%	(7)	(24)%
Elba Express	10	45 %	10	43 %
Texas Intrastate Natural Gas Pipeline Operations	1	1 %	268	45 %
Hiland Midstream	—	— %	49	44 %
All others (including eliminations)	(4)	(1)%	15	2 %
Total Natural Gas Pipelines	$(113)	(10)%	$ 179	9 %

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 three month periods ended March 31, 2017 and 2016:

- decrease of $83 million (72%) from SNG primarily due to our sale of a 50% interest in SNG to The Southern Company on September 1, 2016;
- decrease of $15 million (18%) from CIG primarily due to a decrease in tariff rates effective January 1, 2017 as a result of a rate case settlement entered into in 2016;
- decrease of $15 million (20%) from South Texas Midstream primarily due to lower service revenues resulting primarily from lower volumes partially offset by higher natural gas and NGL prices;
- decrease of $7 million (28%) from KinderHawk primarily due to lower volumes;
- increase of $10 million (45%) from Elba Express primarily due to an expansion project placed in service in December 2016;
- increase of $1 million (1%) 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 transportation and sales margins as a result of higher volumes partially offset by lower storage margins. The increase in revenues of $268 million resulted primarily from an increase in sales revenue due to higher commodity prices which was largely offset by a corresponding increase in costs of sales; and
- Increased commodity prices were the primary drivers of increased Hiland Midstream revenues and cost of sales, which were net of lower inlet and sales volumes.

CO2

	Three Months Ended March 31,	
	2017	2016
	(In millions, except operating statistics)	
Revenues(a)	$303	$302
Operating expenses	(97)	(98)
Gain (loss) on impairments and divestitures, net(b)	1	(21)
Other income	—	1
Earnings from equity investments(b)	11	3
Segment EBDA(b)	218	187
Certain items(b)	4	37
Segment EBDA before certain items	$222	$224
Change from prior period	Increase/(Decrease)	
Revenues before certain items	$(4)	(1)%
Segment EBDA before certain items	$(2)	(1)%
Southwest Colorado CO_2 production (gross)(Bcf/d)(c)	1.3	1.2
Southwest Colorado CO_2 production (net)(Bcf/d)(c)	0.7	0.6
SACROC oil production (gross)(MBbl/d)(d)	28.3	30.5
SACROC oil production (net)(MBbl/d)(e)	23.6	25.4
Yates oil production (gross)(MBbl/d)(d)	17.9	19.0
Yates oil production (net)(MBbl/d)(e)	8.0	8.5
Katz, Goldsmith and Tall Cotton oil production (gross)(MBbl/d)(d)	7.3	6.8
Katz, Goldsmith and Tall Cotton oil production (net)(MBbl/d)(e)	6.2	5.8
NGL sales volumes (net)(MBbl/d)(e)	10.2	9.9
Realized weighted-average oil price per Bbl(f)	$58.14	$59.55
Realized weighted-average NGL price per Bbl(g)	$24.50	$13.32

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Certain items affecting Segment EBDA

(a) 2017 and 2016 amounts include unrealized losses of $5 million and $10 million, respectively, related to derivative contracts used to hedge forecasted commodity sales.

(b) In addition to the revenue certain items described in footnote (a) above: 2017 and 2016 amounts also include a $1 million decrease in expense and a $21 million increase in expense, respectively, related to source and transportation project write-offs. 2016 amount also includes a $6 million decrease in equity earnings for our share of a project write-off recorded by an equity investee.

Other

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

(d) 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.

(e) Net after royalties and outside working interests.

(f) Includes all crude oil production properties.

(g) 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 the comparable three month periods ended March 31, 2017 and 2016.

Three months ended March 31, 2017 versus Three months ended March 31, 2016

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Source and Transportation Activities	$3	4 %	$ 2	2 %
Oil and Gas Producing Activities	(5)	(3)%	(5)	(2)%
Intrasegment eliminations	—	— %	(1)	(10)%
Total CO2	$(2)	(1)%	$ (4)	(1)%

The changes in Segment EBDA for our CO_2 business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable three month periods ended March 31, 2017 and 2016:

- increase of $3 million (4%) from our Source and Transportation activities primarily due to higher revenues of $2 million driven by increased volumes of $7 million partially offset by lower contract sales prices of $5 million and $1 million related to increased earnings from an equity investee; and
- decrease of $5 million (3%) from our Oil and Gas Producing activities primarily due to decreased volumes of $12 million which were partially offset by higher realized NGL prices of $7 million.

Terminals

	Three Months Ended March 31,	
	2017	2016
	(In millions, except operating statistics)	
Revenues(a)	$ 487	$ 465
Operating expenses	(179)	(191)
Loss on impairments and divestitures, net(b)	(7)	(20)
Earnings from equity investments	5	6
Other, net	1	—
Segment EBDA(b)	307	260
Certain items(b)	(5)	16
Segment EBDA before certain items	$ 302	$ 276
Change from prior period	Increase/(Decrease)	
Revenues before certain items	$ 25	5 %
Segment EBDA before certain items	$ 26	9 %
Bulk transload tonnage (MMtons)(c)	14.5	12.3
Ethanol (MMBbl)	17.7	15.3
Liquids leasable capacity (MMBbl)	88.0	86.1
Liquids utilization %(d)	95.3 %	94.8 %

Certain items affecting Segment EBDA

(a) 2017 and 2016 amounts include increases in revenue of $2 million and $5 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: 2017 amount also includes (i) a decrease in expense of $10 million related to a true-up of accrued dredging costs; and (ii) $7 million related to losses on impairments and divestitures, net. 2016 amount also includes (i) $20 million related to losses on impairments and divestitures, net; and (ii) a $1 million increase in expense related to other certain items.

Other

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

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

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Below are the changes in both Segment EBDA before certain items and revenues before certain items, in the comparable three month periods ended March 31, 2017 and 2016.

Three months ended March 31, 2017 versus Three months ended March 31, 2016

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Marine Operations	$13	42 %	$ 15	29 %
Gulf Liquids	9	15 %	12	14 %
Gulf Bulk	4	27 %	2	6 %
Held for sale operations	(5)	(100)%	(11)	(69)%
All others (including intrasegment eliminations)	5	3 %	7	3 %
Total Terminals	$26	9 %	$ 25	5 %

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 three month periods ended March 31, 2017 and 2016:

- increase of $13 million (42%) from our Marine Operations related to the incremental earnings from the May 2016, July 2016, September 2016, December 2016 and March 2017 deliveries of the Jones Act tankers, the Magnolia State, Garden State, Bay State, American Endurance and American Freedom, respectively, partially offset by decreased charter rates on the Golden State, Pelican State, Sunshine State and Empire State Jones Act tankers;
- increase of $9 million (15%) from our Gulf Liquids terminals, primarily related to higher volumes as a result of various expansion projects, including the recently commissioned Kinder Morgan Export Terminal and North Docks terminal, as well as higher rates and ancillary service activities at our Galena Park terminal;
- increase of $4 million (27%) from our Gulf Bulk terminals, primarily related to a contract settlement with a customer emerging from bankruptcy as well as higher coal and petroleum coke volumes handled at our Deepwater terminal; and
- decrease of $5 million (100%) from our sale of certain bulk terminal facilities to an affiliate of Watco Companies, LLC in December 2016 and early 2017.

Products Pipelines

	Three Months Ended March 31,	
	2017	2016
	(In millions, except operating statistics)	
Revenues	$ 402	$ 396
Operating expenses(a)	(129)	(153)
Loss on impairments and divestitures, net(b)	—	(78)
Earnings from equity investments	13	13
Other, net	1	(1)
Segment EBDA(a)(b)	287	177
Certain items(a)(b)	—	108
Segment EBDA before certain items	$ 287	$ 285

Change from prior period	Increase/(Decrease)	
Revenues before certain items	$ 6	2 %
Segment EBDA before certain items	$ 2	1 %

Gasoline (MMBbl)(c)	89.4	88.7
Diesel fuel (MMBbl)	29.0	29.5
Jet fuel (MMBbl)	25.7	25.1
Total refined product volumes (MMBbl)(d)	144.1	143.3
NGL (MMBbl)(d)	9.6	9.4
Crude and condensate (MMBbl)(d)	31.3	30.9
Total delivery volumes (MMBbl)	185.0	183.6
Ethanol (MMBbl)(e)	9.9	10.1

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Certain items affecting Segment EBDA

(a) 2016 amount includes $31 million of rate case liability estimate adjustments associated with prior periods.

(b) 2016 amount includes increases in expense of (i) $64 million related to the Palmetto project write-off; and (ii) a $13 million non-cash impairment charge related to the sale of a Transmix facility.

Other

(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 the comparable three month periods ended March 31, 2017 and 2016.

Three months ended March 31, 2017 versus Three months ended March 31, 2016

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Double H pipeline	$2	15 %	$ 2	11 %

Transmix	1	11 %	6	12 %
Pacific operations	(3)	(4)%	(1)	(1)%
All others (including eliminations)	2	1 %	(1)	— %
Total Products Pipelines	$2	1 %	$ 6	2 %

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 three month periods ended March 31, 2017 and 2016:

- increase of $2 million (15%) primarily due to higher service revenues driven by higher volumes;

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- increase of $1 million (11%) from our Transmix processing operations. The increase in revenue of $6 million and associated increase in costs of goods sold were driven by higher commodity prices; and
- decrease of $3 million (4%) from our Pacific operations primarily due to a change in product gain/loss affecting operating costs and a change in sales mix which resulted in lower service revenues.

Kinder Morgan Canada

	Three Months Ended March 31,	
	2017	2016
	(In millions, except operating statistics)	
Revenues	$ 59	$ 59
Operating expenses	(20)	(18)
Other, net	4	5
Segment EBDA	$ 43	$ 46
Change from prior period	Increase/(Decrease)	
Revenues	$ —	— %
Segment EBDA	$ (3)	(7)%
Transport volumes (MMBbl)(a)	27.6	28.6

(a) Represents Trans Mountain pipeline system volumes.

For the comparable three month period of 2017 and 2016, the Kinder Morgan Canada business segment had a decrease in Segment EBDA of $3 million (7%) primarily due to operating expense timing changes and a 17 percent decrease in volumes to Washington state, caused by narrowing price differentials with competing sources.

General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests

	Three Months Ended March 31,			
	2017	2016	Increase/(decrease)	
	(In millions, except percentages)			
General and administrative(a)	$181	$190	$ (9)	(5)%
Certain items(a)	(7)	(5)	(2)	(40)%
General and administrative and corporate charges before certain items(a)	$174	$185	$ (11)	(6)%
Interest, net(b)	$465	$441	$ 24	5 %
Certain items(b)	12	69	(57)	(83)%
Interest, net, before certain items	$477	$510	$ (33)	(6)%
Net income (loss) attributable to noncontrolling interests	$5	$(1)	$ 6	600 %
Noncontrolling interests associated with certain items(c)	—	6	(6)	(100)%
Net income attributable to noncontrolling interests before certain items	$5	$5	$ —	— %

Certain items
(a)

2017 and 2016 amounts include (i) increases in expense of $2 million and $4 million, respectively, related to certain corporate litigation matters; (ii) increases in expense of $4 million and $3 million, respectively, related to acquisition costs; and (iii) an increase in expense of $1 million and a decrease in expense of $2 million, respectively, related to other certain items.

(b) 2017 and 2016 amounts include (i) decreases in interest expense of $15 million and $19 million, respectively, related to debt fair value adjustments associated with acquisitions; and (ii) an increase in interest expense of $3 million and a decrease in interest expense of $50 million, respectively, related to non-cash true-ups of our estimates of swap ineffectiveness.

(c) 2016 amounts include losses of $6 million associated with Natural Gas Pipelines segment certain items and disclosed above in "—Natural Gas Pipelines."

The decrease in general and administrative expenses and corporate charges before certain items of $11 million in the first quarter of 2017 when compared with the same quarter in the prior year was primarily driven by the sale of a 50% interest in our SNG natural gas pipeline system (effective September 1, 2016), higher capitalized costs and lower legal and insurance costs, partially offset by higher benefit 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 for the first quarter 2017 when compared with the same quarter in the prior year decreased $33 million. The decrease in interest expense was due to lower weighted average debt balances as proceeds from our September 2016 sale of a 50% interest in SNG were used to pay down debt, partially offset by a slightly higher overall weighted average interest rate on our outstanding debt.

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 both March 31, 2017 and December 31, 2016, approximately 28% 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 5 "Risk Management—Interest Rate Risk Management" to our consolidated financial statements.

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 owned by us. Net income attributable to noncontrolling interests before certain items for the first quarter of 2017 when compared with the same quarter in the prior year did not change.

Income Taxes

Our tax expense for the three months ended March 31, 2017 was approximately $246 million as compared to $154 million for the same period of 2016. The $92 million increase in tax expense was primarily due to (i) an increase in our earnings as a result of asset impairments and project write-offs in 2016; and (ii) adjustments to our income tax reserve for uncertain tax positions; partially offset by higher dividend-received deductions from our investment in Florida Gas Transmission Company and Plantation Pipe Line.

Liquidity and Capital Resources

General

As of March 31, 2017, we had $396 million of "Cash and cash equivalents," a decrease of $288 million (42%) from December 31, 2016. We believe our cash position, remaining borrowing capacity on our credit facility (discussed below in "—Short-term Liquidity"), and 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 $886 million and $1,050 million in the first three months of 2017 and 2016, respectively. The period-to-period 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.

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 the need to access the equity capital markets to fund our growth projects for the foreseeable future.

Short-term Liquidity

As of March 31, 2017, 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 March 31, 2017, our $3,928 million of short-term debt consisted primarily of senior notes that mature in the next year. 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, 2016 was $2,696 million.

We had working capital (defined as current assets less current liabilities) deficits of $4,014 million and $2,695 million as of March 31, 2017 and December 31, 2016, 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 $1,319 million (49%) unfavorable change from year-end 2016 was primarily due to a net increase in our current portion of long term debt. 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.

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.”

Our capital expenditures for the three months ended March 31, 2017, and the amount we expect to spend for the remainder of 2017 to sustain and grow our businesses are as follows:

	Three Months Ended March 31, 2017	2017 Remaining	Total
	(In millions)		
Sustaining capital expenditures(a)	$104	$ 532	$636
Discretionary capital investments(b)(c)	$585	$ 2,843	$3,428

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(a) Three-months 2017, 2017 Remaining, and Total 2017 amounts include $18 million, $93 million, and $111 million, respectively, for our proportionate share of sustaining capital expenditures of unconsolidated joint ventures.

(b) Three-months 2017 is net of $216 million of contributions from certain partners for capital investments at non-wholly owned consolidated subsidiaries offset by $189 million of our contributions to certain unconsolidated joint ventures for capital investments, and excludes $34 million of net changes from accrued capital expenditures, contractor retainage and other.

(c) 2017 Remaining amount includes our estimated contributions to certain unconsolidated joint ventures, net of contributions estimated from certain partners in non-wholly owned consolidated subsidiaries for capital investments.

Off Balance Sheet Arrangements

Other than commitments for the purchase of property, plant and equipment discussed below, there have been no material changes in our obligations with respect to other entities that are not consolidated in our financial statements that would affect the disclosures presented as of December 31, 2016 in our 2016 Form 10-K.

Commitments for the purchase of property, plant and equipment as of March 31, 2017 and December 31, 2016 were $1,214 million and $1,112 million, respectively. The $102 million increase is primarily the result of our increase in various capital commitments associated with our natural gas pipeline business segment.

Cash Flows

Operating Activities

The net decrease of $164 million in cash provided by operating activities for the three months of 2017 compared to the respective 2016 period was primarily attributable to:

- an $82 million decrease in operating cash flow resulting from the combined effects of adjusting net income for the period-to-period $131 million increase in non-cash items including the following: (i) net losses on impairments and divestitures of assets and equity investments (see discussion above in "—Results of Operations"); (ii) change in fair market value of derivative contacts; (iii) DD&A expenses (including amortization of excess cost of equity investments); (iv) deferred income taxes; and (v) earnings from equity investments; and
- an $82 million decrease associated with net changes in working capital items and non-current assets and liabilities.

Investing Activities

The $507 million net decrease in cash used in investing activities for the three months of 2017 compared to the respective 2016 period was primarily attributable to:

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- a $326 million decrease in expenditures for acquisitions of assets and investments, primarily driven by the $323 million portion of the purchase price we paid in the 2016 period for the BP terminals acquisition;
- a $147 million reduction in capital expenditures; and
- a $95 million increase in cash for distributions received from equity investment in excess of cumulative earnings; partially offset by
- a $147 million increase in cash used for contributions to equity investments.

Financing Activities

The net increase of $573 million in cash used in financing activities for the three months of 2017 compared to the respective 2016 period was primarily attributable to:

- an $874 million net increase in cash used related to debt activity as a result of net debt payments in the 2017 period compared with net debt proceeds in the 2016 period. See Note 3 “Debt” for further information regarding our debt activity; and
- an $81 million decrease in contributions from noncontrolling interests, primarily reflecting the contributions received from BP for its 25% share of a newly formed joint venture in the 2016 period; partially offset by
- a $391 million increase in cash resulting from contributions received in the 2017 period from EIG, consisting of $387 million for the sale of a 49% partnership interest in ELC and $4 million as an additional contribution for March 2017 capital expenditures.

Common Dividends

We expect to declare common dividends of $0.50 per share on our common stock for 2017 ($0.125/quarter).

Three months ended	Total quarterly dividend per share for the period	Date of declaration	Date of record	Date of dividend
December 31, 2016	$ 0.125	January 18, 2017	February 1, 2017	February 15, 2017
March 31, 2017	$ 0.125	April 19, 2017	May 1, 2017	May 15, 2017

The actual amount of common dividends to be paid on our capital stock will depend on many factors, including our financial condition and results of operations, liquidity requirements, business prospects, capital requirements, legal, regulatory and contractual constraints, tax laws, Delaware laws and other factors. See Item 1A. “Risk Factors—The guidance we provide for our anticipated dividends is based on estimates. Circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business.” of our 2016 Form 10-K. All of these matters will be taken into consideration by our board of directors in declaring dividends.

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

Preferred Dividends

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

Period	Total dividend per share for the period	Date of declaration	Date of record	Date of dividend
October 26, 2016 through January 25, 2017	$24.375000	October 19, 2016	January 11, 2017	January 26, 2017

January 26, 2017 through April 25, 2017	$24.375000	January 18, 2017	April 11, 2017	April 26, 2017

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

There have been no material changes in market risk exposures that would affect the quantitative and qualitative disclosures presented as of December 31, 2016, in Item 7A in our 2016 Form 10-K. For more information on our risk management activities, see Item 1, Note 5 “Risk Management” to our consolidated financial statements.

Item 4. Controls and Procedures.

As of March 31, 2017, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. There has been no change in our internal control over financial reporting during the quarter ended March 31, 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

See Part I, Item 1, Note 9 to our consolidated financial statements entitled “Litigation, Environmental and Other Contingencies” which is incorporated in this item by reference.

Item 1A. Risk Factors.

There have been no material changes in the risk factors disclosed in Part I, Item 1A in our 2016 Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

None.

Item 3. Defaults Upon Senior Securities.

None.

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 included in exhibit 95.1 to this quarterly report.

Item 5. Other Information.

None.

Item 6. Exhibits.

3.1	*	Amended and Restated Certificate of Incorporation of KMI (filed as Exhibit 3.1 to KMI's Quarterly Report on Form 10 Q for the three months ended June 30, 2015 (file No. 001-35081)).
3.2	*	Amended and Restated Bylaws of KMI (filed as Exhibit 3.1 to KMI's Current Report on Form 8 K, filed January 24, 2017 (File No. 001-35081)).
10.1		Cross Guarantee Agreement, dated as of November 26, 2014, among Kinder Morgan, Inc. and certain of its subsidiaries, with schedules updated as of March 31, 2017.
31.1		Certification by Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2		Certification by Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1		Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2		Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95.1		Mine Safety Disclosures.
101		Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the three months ended March 31, 2017 and 2016; (ii) our Consolidated Statements of Comprehensive Income for the three months ended March 31, 2017 and 2016; (iii) our Consolidated Balance Sheets as of March 31, 2017 and December 31, 2016; (iv) our Consolidated Statements of Cash Flows for the three months ended March 31, 2017 and 2016; (v) our Consolidated Statements of Stockholders' Equity for the three months ended March 31, 2017 and 2016; and (vi) the notes to our Consolidated Financial Statements.

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

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

KINDER MORGAN, INC.
Registrant

Date: April 21, 2017 By: /s/ Kimberly A. Dang
Kimberly A. Dang
Vice President and Chief Financial Officer
(principal financial and accounting officer)

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