KINDER MORGAN, INC.
Form 10-Q
July 22, 2016

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 June 30, 2016

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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting 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

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 July 21, 2016, the registrant had 2,232,323,355 Class P shares outstanding.

KINDER MORGAN, INC. AND SUBSIDIARIES
TABLE OF CONTENTS

		Page Number
	Glossary	2
	Information Regarding Forward-Looking Statements	3
	PART I. FINANCIAL INFORMATION	
Item 1.	Financial Statements (Unaudited)	
	Consolidated Statements of Income - Three and Six Months Ended June 30, 2016 and 2015	4
	Consolidated Statements of Comprehensive Income - Three and Six Months Ended June 30, 2016 and 2015	5
	Consolidated Balance Sheets - June 30, 2016 and December 31, 2015	6
	Consolidated Statements of Cash Flows - Six Months Ended June 30, 2016 and 2015	7
	Consolidated Statements of Stockholders' Equity - Six Months Ended June 30, 2016 and 2015	8
	Notes to Consolidated Financial Statements	9
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	
	General and Basis of Presentation	42
	Results of Operations	42
	Liquidity and Capital Resources	56
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	60
Item 4.	Controls and Procedures	60
	PART II. OTHER INFORMATION	
Item 1.	Legal Proceedings	60
Item 1A.	Risk Factors	60
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	60
Item 3.	Defaults Upon Senior Securities	60
Item 4.	Mine Safety Disclosures	60
Item 5.	Other Information	60
Item 6.	Exhibits	61
	Signature	62

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.	KMLP	= Kinder Morgan Louisiana Pipeline LLC
Elba Express	= Elba Express Company, L.L.C.	KMP	= Kinder Morgan Energy Partners, L.P. and its majority-owned and controlled subsidiaries
EPB	= El Paso Pipeline Partners, L.P. and its majority-owned and controlled subsidiaries	KMR	= Kinder Morgan Management, LLC
EPNG	= El Paso Natural Gas Company, L.L.C.	SFPP	= SFPP, L.P.
Hiland	= Hiland Partners, LP	SLNG	= Southern LNG Company, L.L.C.
KMEP	= Kinder Morgan Energy Partners, L.P.	SNG	= Southern Natural Gas Company, L.L.C.
KMGP	= Kinder Morgan G.P., Inc.	TGP	= Tennessee Gas Pipeline Company, L.L.C.

Unless the context otherwise requires, references to “we,” “us,” or “our,” 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, 2015 (2015 Form 10-K) and Item 1A “Risk Factors” included elsewhere in this report 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Revenues				
Natural gas sales	$478	$677	$1,021	$1,462
Services	2,034	1,963	4,148	3,933
Product sales and other	632	823	1,170	1,665
Total Revenues	3,144	3,463	6,339	7,060
Operating Costs, Expenses and Other				
Costs of sales	752	1,085	1,483	2,175
Operations and maintenance	603	590	1,168	1,095
Depreciation, depletion and amortization	552	570	1,103	1,108
General and administrative	189	164	379	380
Taxes, other than income taxes	110	116	218	231
(Gain) loss on impairments and disposals of long-lived assets, net	(4)	50	231	104
Other expense (income), net	2	(4)	1	(3)
Total Operating Costs, Expenses and Other	2,204	2,571	4,583	5,090
Operating Income	940	892	1,756	1,970
Other Income (Expense)				
Earnings from equity investments	106	114	200	190
Amortization of excess cost of equity investments	(16)	(14)	(30)	(26)
Interest, net	(471)	(472)	(912)	(984)
Other, net	29	11	42	24
Total Other Expense	(352)	(361)	(700)	(796)
Income Before Income Taxes	588	531	1,056	1,174
Income Tax Expense	(213)	(189)	(367)	(413)
Net Income	375	342	689	761
Net (Income) Loss Attributable to Noncontrolling Interests	(3)	(9)	(2)	1
Net Income Attributable to Kinder Morgan, Inc.	372	333	687	762
Preferred Stock Dividends	(39)	—	(78)	—
Net Income Available to Common Stockholders	$333	$333	$609	$762

Class P Shares				
Basic Earnings Per Common Share	$0.15	$0.15	$0.27	$0.35
Basic Weighted Average Common Shares Outstanding	2,229	2,175	2,229	2,158
Diluted Earnings Per Common Share	$0.15	$0.15	$0.27	$0.35
Diluted Weighted Average Common Shares Outstanding	2,229	2,187	2,229	2,169
Dividends Per Common Share Declared for the Period	$0.125	$0.490	$0.250	$0.970

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net income	$375	$342	$689	$761
Other comprehensive income (loss), net of tax				
Change in fair value of hedge derivatives (net of tax benefit of $82, $34, $40 and $35, respectively)	(142)	(58)	(69)	(60)
Reclassification of change in fair value of derivatives to net income (net of tax benefit of $6, $33, $69 and $74, respectively)	(11)	(57)	(119)	(129)
Foreign currency translation adjustments (net of tax (expense) benefit of $(4), $(9), $(49) and $53, respectively)	7	17	85	(91)
Benefit plan adjustments (net of tax expense of $(3), $-, $(6) and $(4), respectively)	6	—	10	6
Total other comprehensive loss	(140)	(98)	(93)	(274)
Comprehensive income	235	244	596	487
Comprehensive (income) loss attributable to noncontrolling interests	(3)	(9)	(2)	1
Comprehensive income attributable to KMI	$232	$235	$594	$488

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)

	June 30, 2016 (Unaudited)	December 31, 2015
ASSETS		
Current Assets		
Cash and cash equivalents	$ 180	$ 229
Accounts receivable, net	1,278	1,315
Fair value of derivative contracts	313	507
Inventories	361	407
Other current assets	338	366
Total current assets	2,470	2,824
Property, plant and equipment, net	41,199	40,547
Investments	6,202	6,040
Goodwill	23,802	23,790
Other intangibles, net	3,440	3,551
Deferred income taxes	4,975	5,323
Deferred charges and other assets	2,229	2,029
Total Assets	$ 84,317	$ 84,104
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of debt	$ 3,419	$ 821
Accounts payable	1,087	1,324
Accrued interest	630	695
Accrued contingencies	405	298
Other current liabilities	1,025	927
Total current liabilities	6,566	4,065
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	38,113	40,632
Preferred interest in general partner of KMP	100	100
Debt fair value adjustments	1,988	1,674
Total long-term debt	40,201	42,406
Other long-term liabilities and deferred credits	2,077	2,230
Total long-term liabilities and deferred credits	42,278	44,636
Total Liabilities	48,844	48,701
Commitments and contingencies (Notes 3 and 9)		
Stockholders' Equity		
Class P shares, $0.01 par value, 4,000,000,000 shares authorized, 2,229,330,134 and 2,229,223,864 shares, respectively, issued and outstanding	22	22
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 9.75% Series A Mandatory Convertible, $1,000 per share liquidation preference, 1,600,000 shares issued and outstanding	—	—
Additional paid-in capital	41,696	41,661
Retained deficit	(6,053)	(6,103)
Accumulated other comprehensive loss	(554)	(461)
Total Kinder Morgan, Inc.'s stockholders' equity	35,111	35,119
Noncontrolling interests	362	284

Total Stockholders' Equity	35,473	35,403
Total Liabilities and Stockholders' Equity	$ 84,317	$ 84,104

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

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

	Six Months Ended June 30,	
	2016	2015
Cash Flows From Operating Activities		
Net income	$689	$761
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	1,103	1,108
Deferred income taxes	388	413
Amortization of excess cost of equity investments	30	26
Loss on impairments and disposals of long-lived assets, net	231	104
Earnings from equity investments	(200)	(190)
Distributions from equity investment earnings	203	187
Noncash pension benefit credits	—	(23)
Changes in components of working capital, net of the effects of acquisitions and dispositions		
Accounts receivable, net	81	366
Income tax receivable	—	195
Inventories	49	(34)
Other current assets	7	50
Accounts payable	(144)	(222)
Accrued interest, net of interest rate swaps	(49)	9
Accrued contingencies and other current liabilities	72	(7)
Rate reparations, refunds and other litigation reserve adjustments	31	27
Other, net	(147)	(232)
Net Cash Provided by Operating Activities	2,344	2,538
Cash Flows From Investing Activities		
Acquisitions of assets and investments, net of cash acquired	(333)	(1,919)
Capital expenditures	(1,470)	(1,909)
Sale of property, plant and equipment, investments, and other net assets, net of removal costs	220	4
Contributions to investments	(363)	(45)
Distributions from equity investments in excess of cumulative earnings	81	114
Other, net	(15)	11
Net Cash Used in Investing Activities	(1,880)	(3,744)
Cash Flows From Financing Activities		
Issuances of debt	6,847	9,485
Payments of debt	(6,800)	(8,941)
Debt issue costs	(6)	(20)
Issuances of common shares	—	2,562
Cash dividends - common shares	(559)	(2,006)
Cash dividends - preferred shares	(76)	—
Repurchases of warrants	—	(5)
Contributions from noncontrolling interests	87	—
Distributions to noncontrolling interests	(11)	(16)
Other, net	—	(1)
Net Cash (Used in) Provided by Financing Activities	(518)	1,058

Effect of Exchange Rate Changes on Cash and Cash Equivalents	5	(4)
Net decrease in Cash and Cash Equivalents	(49)	(152)
Cash and Cash Equivalents, beginning of period	229	315
Cash and Cash Equivalents, end of period	$180	$163
Non-cash Investing and Financing Activities		
Assets acquired by the assumption or incurrence of liabilities	$43	$1,671
Net assets contributed to equity investment	$37	$34
Supplemental Disclosures of Cash Flow Information		
Cash paid during the period for interest (net of capitalized interest)	$1,047	$1,002
Cash paid (refunded) during the period for income taxes, net	$5	$(185)

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		Preferred stock							
	Issued shares	Par value	Issued shares	Par value	Additional paid-in capital	Retained deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
Balance at December 31, 2015	2,229	$ 22	2	$ —	$ 41,661	$ (6,103)	$ (461)	$ 35,119	$ 284	$ 35,403
Restricted shares					35			35		35
Net income						687		687	2	689
Distributions								—	(11)	(11)
Contributions								—	87	87
Preferred stock dividends						(78)		(78)		(78)
Common stock dividends						(559)		(559)		(559)
Other comprehensive loss							(93)	(93)		(93)
Balance at June 30, 2016	2,229	$ 22	2	$ —	$ 41,696	$ (6,053)	$ (554)	$ 35,111	$ 362	$ 35,473

	Common stock		Preferred stock							
	Issued shares	Par value	Issued shares	Par value	Additional paid-in capital	Retained deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
Balance at December 31, 2014	2,125	$ 21	—	$ —	$ 36,178	$ (2,106)	$ (17)	$ 34,076	$ 350	$ 34,426
Issuances of common shares	62	1			2,561			2,562		2,562
Repurchase of warrants					(5)			(5)		(5)
EP Trust I Preferred security conversions	1				23			23		23
Warrants exercised					2			2		2
Restricted shares					32			32		32
Net income						762		762	(1)	761
Distributions								—	(16)	(16)
Common stock dividends						(2,006)		(2,006)		(2,006)
Other comprehensive loss							(274)	(274)		(274)
Balance at June 30, 2015	2,188	$ 22	—	$ —	$ 38,791	$ (3,350)	$ (291)	$ 35,172	$ 333	$ 35,505

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 the largest energy infrastructure company in North America. We own an interest in or operate approximately 84,000 miles of pipelines and 180 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 coal, petroleum coke and steel. We are also the leading producer and transporter of CO_2, which is utilized for enhanced oil recovery projects in North America.

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

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 2015 Form 10-K.

Goodwill

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

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

Step 1 involves comparing the estimated fair value of each respective reporting unit to its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, the reporting unit's goodwill is not considered impaired. If the carrying value exceeds the estimated fair value, step 2 must be performed to determine whether goodwill is impaired and, if so, the amount of the impairment. Step 2 involves calculating an implied fair value of goodwill by performing a hypothetical allocation of the estimated fair value of the reporting unit determined in step 1 to the respective tangible and intangible net assets of the reporting unit. The remaining implied goodwill is then compared to the actual carrying amount of the goodwill for the reporting unit. To the extent the carrying amount of goodwill exceeds the implied goodwill, the difference is the amount of the goodwill impairment. A large portion of our goodwill is non-deductible for tax purposes, and as such, to the extent there are impairments, all or a portion of the impairment may not result in a corresponding tax benefit.

In the fourth quarter 2015, we recorded a $1,150 million impairment of goodwill associated with our Natural Gas Pipeline - Non-Regulated reporting unit triggered by decreases in market valuations in our industry which were caused by the commodity price environment at that time.

The results of our May 31, 2016 annual impairment test indicated that for each of our reporting units other than our Natural Gas Pipelines - Non-Regulated, the reporting unit fair value exceeded the carrying value. For our Natural Gas Pipelines - Non-Regulated, and similar to December 31, 2015, the fair value of the reporting unit continues to be slightly less than the carrying value of the reporting unit, thereby necessitating a step 2 evaluation. The hypothetical fair value allocation to the assets and liabilities of the reporting unit in the step 2 evaluation, resulted in an amount of implied goodwill exceeding the carrying amount of the reporting unit's goodwill and, as a result, no adjustment to the reporting unit's goodwill carrying value was warranted.

The fair value estimates used in the step 1 and step 2 goodwill tests are based on Level 3 inputs of the fair value hierarchy. The methodologies and key inputs used by management were substantially consistent with those utilized in the fourth quarter 2015.

We expect that the carrying value of our Natural Gas Pipelines - Non-Regulated reporting unit will continue to approximate fair value so long as our estimate of future cash flows and the market valuation remain consistent with current levels. A continued or prolonged period of lower commodity prices could result in further deterioration of market multiples, comparable sales transactions prices, weighted average costs of capital, and our cash flow estimates. Changes to any one or combination of these factors, particularly for our Natural Gas Pipelines - Non-Regulated reporting unit given that the carrying value slightly exceeds the current estimated fair value, would result in a change to the reporting unit fair values discussed above which could lead to further impairment charges. Such potential impairment could have a significant effect on our results of operations.

Impairments and Disposals

During the six months ended June 30, 2016, we had non-cash pre-tax impairment charges and losses on disposals of assets of $257 million substantially all of which was recorded in the first quarter of 2016 comprised of (i) $106 million of project write-offs on our Northeast Energy Direct (NED) Market project and $13 million related to an equity investment in a gas gathering entity within our Natural Gas Pipelines business segment; (ii) $33 million of project write-offs within our CO_2 business segment; (iii) $20 million related to certain terminals with significant coal operations within our Terminals business segment; (iv) $64 million of write-offs associated with our Palmetto project and an $8 million loss on a held-for-sale Transmix facility both within our Products Pipelines business segment; and (v) $13 million net losses on other disposals of assets. The project write-offs recorded in the six months ended June 30, 2016 were driven by management's assessment of the probability of those projects moving forward based on insufficient progress in obtaining contractual commitments from customers in the New England market, in the case of the NED Market project, and an unfavorable action by the Georgia legislature regarding permitting for refined products pipelines affecting the Palmetto project.

During the three and six months ended June 30, 2015 we had non-cash pre-tax impairment charges and losses on disposals of assets of $50 million and $130 million, respectively. These amounts include (i) $48 million and $99 million for the three and six months ended June 30, 2015, respectively, of impairments and project write-offs, related to certain gas gathering and processing assets within our midstream operations and $26 million for the six months ended June 30, 2015 primarily related to an equity investment in a gathering entity, both within our Natural Gas Pipelines business segment; (ii) $9 million for both the three and six months ended June 30, 2015 related to an impairment charge associated with the pending sale of excess construction pipe within our CO_2 business segment; and (iii) $7 million and $4 million for the three and six months ended June 30, 2015, respectively, of net gains on other disposals of assets.

In addition, during the three and six months ended June 30, 2016 we recognized a $12 million gain on the sale of an equity investment, which is included in “Other, net” on the accompanying consolidated statements of income.

As conditions warrant, we routinely evaluate our assets for potential triggering events that could impact the fair value of certain assets or our ability to recover the carrying value of long-lived assets. Such assets include accounts receivable, equity investments, goodwill, other intangibles and property plant and equipment, including oil and gas properties and in-process construction. Depending on the nature of the asset, these evaluations require the use of significant judgments including but not limited to judgments related to customer credit worthiness, future cash flow estimates, future volume expectations, current and future commodity prices, regulatory environment, management’s decisions to dispose of certain assets and estimates of the fair values of our reporting units, as well as general economic conditions and the related demand for products handled or transported by our assets. In the current commodity price environment and to the extent conditions further deteriorate, we may identify additional triggering events that may require future evaluations of the recoverability of the carrying value of our long-lived assets, investments and goodwill which could result in further impairment charges. Because certain of our assets, including our oil and gas producing properties have been written down to fair value, any deterioration in fair value that exceeds the rate of depletion of the related asset would result in further impairments. Such non-cash impairments could have a significant effect on our results of operations, which would be recognized in the period in which the carrying value is determined to not be recoverable. Certain of these impairments are based on Level 3 estimates of fair value using income approach valuation methodologies which include assumptions regarding future cash flows, terminal values and discount rates. We believe our methodologies are standard techniques and results would not vary materially using a reasonable range of assumptions.

Earnings per Share

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Class P	$332	$330	$607	$756
Participating securities:				
Restricted stock awards(a)	1	3	2	6
Net Income Available to Common Stockholders	$333	$333	$609	$762

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Basic Weighted Average Common Shares Outstanding	2,229	2,175	2,229	2,158
Effect of dilutive securities:				
Warrants	—	12	—	11
Diluted Weighted Average Common Shares Outstanding	2,229	2,187	2,229	2,169

____

(a) As of June 30, 2016, there were approximately 8 million such restricted stock awards.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Unvested restricted stock awards	8	7	8	7
Warrants to purchase our Class P shares(a)	293	287	293	288
Convertible trust preferred securities	8	8	8	9
Mandatory convertible preferred stock(b)	58	n/a	58	n/a

____

n/a - not applicable

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

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

2. Acquisitions and Divestitures

Acquisition of Terminal Assets from and Joint Venture With BP Products North America Inc. (BP)

On February 1, 2016, we completed the acquisition of 15 products terminals and associated infrastructure from BP for $349 million, including a transaction deposit paid in 2015 and working capital adjustments paid in 2016. In conjunction with this transaction, we and BP formed a joint venture, with an equity ownership interest of 75% and 25%, respectively. Subsequent to the acquisition, we contributed 14 of the acquired terminals to the joint venture, which we operate, and the remaining terminal is solely owned by us. BP acquired its 25% interest in the joint venture for $84 million, which we reported as “Contributions from noncontrolling interests” within our accompanying consolidated statement of cash flows for the six months ended June 30, 2016. Of the acquired assets, 10 terminals are included in our Terminals business segment and 5 terminals are included in our Products Pipelines business segment based on synergies with each segment’s respective existing operations.

Allocation of Purchase Price

The evaluation of the assigned fair values for the BP terminals acquisition is ongoing and subject to adjustment. As of June 30, 2016, our preliminary allocation of the purchase price for the BP terminals acquisition and the adjusted purchase price allocations for the Hiland acquisition and Royal Vopak terminals acquisition, both completed in February 2015, are detailed below (in millions).

	Acquisitions		
	BP Terminal Assets	Hiland	Royal Vopak Terminal Assets
Purchase Price Allocation:			
Current assets	$2	$79	$ 2
Property, plant and equipment	396	1,492	155
Goodwill	—	310	6
Deferred charges and other assets(a)	—	1,498	—

Total assets acquired	398	3,379	163
Current liabilities	—	(253)	(1)
Debt	—	(1,413)	—
Other liabilities	(49)	(4)	(4)
Cash consideration	$349	$1,709	$ 158

(a) Primarily consists of customer contracts and relationships with a weighted average amortization period of 16.4 years.

12

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

Subsequent Event—Sale of Equity Interest in SNG

On July 10, 2016, we announced the anticipated sale of a 50% interest in our SNG natural gas pipeline system to The Southern Company (Southern Company) for an expected $1.47 billion and the formation of a joint venture, which will include our remaining 50% interest in SNG, which we will operate. Inclusive of existing SNG debt, the transaction equates to an SNG total enterprise value of $4.15 billion. Subject to customary closing conditions and regulatory approvals, the transaction is expected to close in the third or early fourth quarter of 2016, at which time, any difference between the sales price and the proportionate carrying value of the interests in SNG being sold would be recognized.

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):

	June 30, 2016	December 31, 2015
KMI		
Unsecured term loan facility, variable rate, due January 26, 2019(a)	$1,000	$ —
Senior notes, 1.50% through 8.25%, due 2016 through 2098(b)	13,309	13,346
Credit facility due November 26, 2019(c)	700	—
Commercial paper borrowings(c)	24	—
KMP		
Senior notes, 2.65% through 9.00%, due 2016 through 2044	19,485	19,985
TGP senior notes, 7.00% through 8.375%, due 2016 through 2037(a)	1,540	1,790
EPNG senior notes, 5.95% through 8.625%, due 2017 through 2032	1,115	1,115
Copano senior notes, 7.125%, due April 1, 2021	332	332
CIG senior notes, 6.85%, due June 15, 2037	100	100
SNG notes, 4.40% through 8.00%, due 2017 through 2032	1,211	1,211
Other Subsidiary Borrowings (as obligor)		
Kinder Morgan Finance Company, LLC, senior notes, 5.70% through 6.40%, due 2016 through 2036(a)	786	1,636
Hiland Partners Holdings LLC, senior notes, 5.50% and 7.25%, due 2020 and 2022	974	974
EPC Building, LLC, promissory note, 3.967%, due 2016 through 2035	438	443
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	297	300

Total debt – KMI and Subsidiaries	41,632	41,553
Less: Current portion of debt(a)(d)	3,419	821
Total long-term debt – KMI and Subsidiaries(e)	$38,213	$ 40,732

____

(a) On January 26, 2016, we entered into a $1.0 billion three-year unsecured term loan facility with a variable interest rate, which is determined in the same manner as interest on our revolving credit facility borrowings. In January 2016, we repaid $850 million of maturing 5.70% senior notes, and in February 2016, we repaid $250 million of maturing 8.00% senior notes primarily using proceeds

13

from the three-year term loan. Since we refinanced a portion of the maturing debt with proceeds from long-term debt, we classified $1 billion of the maturing debt within "Long-term debt" on our consolidated balance sheet as of December 31, 2015.

(b) Amount includes senior notes that are denominated in Euros and have been converted and are respectively reported above at the June 30, 2016 exchange rate of 1.1106 U.S. dollars per Euro and the December 31, 2015 exchange rate of 1.0862 U.S. dollars per Euro. For the six months ended June 30, 2016, our debt increased by $31 million as a result of the change in the exchange rate of U.S. dollars per Euro. 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").

(c) As of June 30, 2016, the weighted average interest rate on our credit facility borrowings, including commercial paper borrowings, was 1.91%.

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

(e) Excludes our "Debt fair value adjustments" which, as of June 30, 2016 and December 31, 2015, increased our combined debt balances by $1,988 million and $1,674 million, respectively. In addition to all unamortized debt discount/premium amounts, debt issuance costs and purchase accounting on our debt balances, our debt fair value adjustments also include amounts associated with the offsetting entry for hedged debt and any unamortized portion of proceeds received from the early termination of interest rate swap agreements.

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

On January 26, 2016, in accordance with the terms of our revolving credit agreement, we increased the capacity of our revolving credit agreement from $4.0 billion to $5.0 billion. The other terms of the revolving credit agreement remain the same. Our availability under this facility as of June 30, 2016 was $4,102 million, which is net of borrowings, and $174 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

In addition to outstanding credit facility borrowings, commercial paper borrowings, and other debt maturing within 12 months, our current portion of debt includes the current portion of the following significant series of long-term notes:

As of June 30, 2016	$600 million 6.00% notes due February 2017
	$300 million 7.50% notes due April 2017
	$355 million 5.95% notes due April 2017
	$500 million 5.90% notes due April 2017
	$786 million 7.00% notes due June 2017
As of December 31, 2015	$500 million 3.50% notes due March 2016

Long-term Debt Issuances and Repayments

The following are significant long-term debt issuances and repayments made during the six months ended June 30, 2016:

Issuances	$1.0 billion unsecured term loan facility due 2019
Repayments	$850 million 5.70% notes due 2016

$500 million 3.50% notes due 2016
$250 million 8.00% notes due 2016
$67 million 8.25% notes due 2016

4. Stockholders' Equity

Common Equity

As of June 30, 2016, 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 2015 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. The following table provides information about our per share dividends:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Per common share cash dividend declared for the period	$0.125	$0.49	$0.250	$0.97
Per common share cash dividend paid in the period	$0.125	$0.48	$0.250	$0.93

On July 20, 2016, our board of directors declared a cash dividend of $0.125 per common share for the quarterly period ended June 30, 2016, which is payable on August 15, 2016 to common shareholders of record as of August 1, 2016.

Mandatory Convertible Preferred Stock

On October 30, 2015, we completed an offering of 32,000,000 depositary shares, each of which represents a 1/20th interest in a share of our 1,600,000 shares of 9.750% Series A mandatory convertible preferred stock, with a liquidating preference of $1,000 per share (equal to a $50 liquidation preference per depositary share). For additional information regarding our mandatory convertible preferred stock, see Note 11 to our consolidated financial statements included in our 2015 Form 10-K.

Preferred Dividends

On April 20, 2016, 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 April 26, 2016 through and including July 25, 2016, which is payable on July 26, 2016 to mandatory convertible preferred shareholders of record as of July 11, 2016.

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 certain of these risks. In addition, prior to May 2016, we had power forward and swap contracts related to legacy operations of acquired businesses.

Energy Commodity Price Risk Management

As of June 30, 2016, we had the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Net open position long/(short)	
Derivatives designated as hedging contracts		
Crude oil fixed price	(21.2)	MMBbl
Crude oil basis	(4.1)	MMBbl
Natural gas fixed price	(31.9)	Bcf
Natural gas basis	(21.8)	Bcf

Derivatives not designated as hedging contracts		
Crude oil fixed price	(0.3)	MMBbl
Crude oil basis	(0.4)	MMBbl
Natural gas fixed price	(12.8)	Bcf
Natural gas basis	(2.6)	Bcf
NGL and other fixed price	(3.4)	MMBbl

As of June 30, 2016, the maximum length of time over which we have hedged, for accounting purposes, our exposure to the variability in future cash flows associated with energy commodity price risk is through December 2020.

Interest Rate Risk Management

As of June 30, 2016, we had a combined notional principal amount of $9,775 million of fixed-to-variable interest rate swap agreements, of which $8,475 million were designated as fair value hedges. As of December 31, 2015, we had a combined notional principal amount of $11,000 million of fixed-to-variable interest rate swap agreements, of which $9,700 million were designated as fair value hedges. All of our swap agreements effectively convert the interest expense associated with certain series of senior notes from fixed rates to variable rates based on an interest rate of 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 June 30, 2016, the maximum length of time over which we have hedged a portion of our exposure to the variability in the value of this debt due to interest rate risk is through March 15, 2035.

Foreign Currency Risk Management

In connection with the issuance of our Euro denominated senior notes in March 2015 (see Note 3), we entered into $1,358 million cross-currency swap agreements to manage the related foreign currency risk by effectively converting all of the fixed-rate Euro denominated debt, including annual interest payments and the payment of principal at maturity, to U.S. dollar denominated debt at fixed rates equivalent to approximately 3.79% and 4.67% for the 7-year and 12-year senior notes, respectively. These cross-currency swaps are accounted for as cash flow hedges. The terms of the cross-currency swap agreements correspond to the related hedged senior notes, and such agreements have the same maturities as the hedged senior notes.

Fair Value of Derivative Contracts

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

Fair Value of Derivative Contracts

	Location	Asset derivatives		Liability derivatives	
		June 30, 2016	December 31, 2015	June 30, 2016	December 31, 2015
		Fair value		Fair value	
Derivatives designated as hedging contracts					
Natural gas and crude derivative contracts	Fair value of derivative contracts/(Other current liabilities)	$177	$ 359	$(38)	$ (13)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	139	244	(18)	—
Subtotal		316	603	(56)	(13)
Interest rate swap agreements	Fair value of derivative contracts/(Other current liabilities)	117	111	—	—
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	657	273	—	(9)
Subtotal		774	384	—	(9)
Cross-currency swap agreements	Fair value of derivative contracts/(Other current liabilities)	—	—	(22)	(6)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	13	—	(12)	(46)
Subtotal		13	—	(34)	(52)
Total		1,103	987	(90)	(74)
Derivatives not designated as hedging contracts					
Natural gas, crude, NGL and other derivative contracts	Fair value of derivative contracts/(Other current liabilities)	7	35	(10)	(1)
Subtotal		7	35	(10)	(1)
Interest rate swap agreements	Fair value of derivative contracts/(Other current liabilities)	12	1	—	(11)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	50	—	—	(5)
Subtotal		62	1	—	(16)
Power derivative contracts	Fair value of derivative contracts/(Other current liabilities)	—	1	—	(17)
Subtotal		—	1	—	(17)
Total		69	37	(10)	(34)
Total derivatives		$1,172	$ 1,024	$(100)	$ (108)

Effect of Derivative Contracts on the Income Statement

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

Derivatives in fair value hedging relationships	Location	Gain/(loss) recognized in income on derivatives and related hedged item			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2016	2015	2016	2015
Interest rate swap agreements	Interest, net	$119	$(233)	$399	$(88)
Hedged fixed rate debt	Interest, net	$(120)	$256	$(404)	$117

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 June 30,			Three Months Ended June 30,			Three Months Ended June 30,	
	2016	2015		2016	2015		2016	2015
Energy commodity derivative contracts	$(111)	$(82)	Revenues—Natural gas sales	$ 2	$ 1	Revenues—Natural gas sales	$ —	$ —
			Revenues—Product sales and other	33	37	Revenues—Product sales and other	(6)	3
			Costs of sales	(2)	(14)	Costs of sales	—	—
Interest rate swap agreements(c)	(1)	1	Interest, net	—	—	Interest, net	—	—
Cross-currency swap	(30)	23	Other, net	(22)	33	Other, net	—	—
Total	$(142)	$(58)	Total	$ 11	$ 57	Total	$ (6)	$ 3

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)	
	Six Months Ended June 30,			Six Months Ended June 30,			Six Months Ended June 30,	
	2016	2015		2016	2015		2016	2015
Energy commodity	$(84)	$(47)	Revenues—Natural	$ 23	$ 25	Revenues—Natural	$ —	$ —

derivative contracts			gas sales			gas sales		
			Revenues—Product sales and other	90	101	Revenues—Product sales and other	(5)	10
			Costs of sales	(12)	(19)	Costs of sales	—	—
Interest rate swap agreements(c)	(5)	(2)	Interest, net	(1)	(1)	Interest, net	—	—
Cross-currency swap	20	(11)	Other, net	19	23	Other, net	—	—
Total	$(69)	$(60)	Total	$ 119	$ 129	Total	$ (5)	$ 10

_____

(a) We expect to reclassify an approximate $46 million gain associated with cash flow hedge price risk management activities included in our accumulated other comprehensive loss balances as of June 30, 2016 into earnings during the next twelve months (when the associated forecasted sales and purchases 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 June 30,		Six Months Ended June 30,	
		2016	2015	2016	2015
Energy commodity derivative contracts	Revenues—Natural gas sales	$(11)	$(2)	$(5)	$ 3
	Revenues—Product sales and other	(12)	(40)	(14)	4
	Costs of sales	3	3	(2)	—
Interest rate swap agreements	Interest, net	24	—	77	—
Total(a)		$4	$(39)	$56	$ 7

____

(a) Three and six months ended June 30, 2016 includes an approximate gain of $20 million and $39 million, respectively, associated with natural gas, crude and NGL derivative contract settlements. Three and six months ended June 30, 2015 includes an approximate gain of $7 million and $2 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 June 30, 2016 and December 31, 2015, we had no and $2 million of outstanding letters of credit supporting our commodity price risk management program. As of June 30, 2016, we had cash margins of $18 million posted by us as collateral and no amounts posted by our counterparties as collateral. As of December 31, 2015, we had no cash margins posted by us as collateral and cash margins of $37 million posted by our counterparties as collateral. We also use industry standard commercial agreements which allow for the netting of exposures associated with transactions executed under a single commercial agreement. Additionally, we generally utilize 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 June 30, 2016, 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, 2015	$ 219	$ (322)	$ (358)	$ (461)
Other comprehensive (loss) gain before reclassifications	(69)	85	10	26
Gains reclassified from accumulated other comprehensive income (loss)	(119)	—	—	(119)
Net current-period other comprehensive (loss) income	(188)	85	10	(93)
Balance as of June 30, 2016	$ 31	$ (237)	$ (348)	$ (554)

	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, 2014	$ 327	$ (108)	$ (236)	$ (17)
Other comprehensive (loss) gain before reclassifications	(60)	(91)	6	(145)
Gains reclassified from accumulated other comprehensive income (loss)	(129)	—	—	(129)
Net current-period other comprehensive (loss) income	(189)	(91)	6	(274)
Balance as of June 30, 2015	$ 138	$ (199)	$ (230)	$ (291)

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).

20

Fair Value of Derivative Contracts

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

	Balance sheet asset fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Cash collateral held(b)	Net amount
As of June 30, 2016							
Energy commodity derivative contracts(a)	$6	$317	$ —	$ 323	$(32)	$ —	$ 291
Interest rate swap agreements	$—	$836	$ —	$ 836	$—	$ —	$ 836
Cross-currency swap agreements	$—	$13	$ —	$ 13	$(13)	$ —	$ —
As of December 31, 2015							
Energy commodity derivative contracts(a)	$48	$589	$ 2	$ 639	$(12)	$ (37)	$ 590
Interest rate swap agreements	$—	$385	$ —	$ 385	$(8)	$ —	$ 377
Cross-currency swap agreements	$—	$—	$ —	$ —	$—	$ —	$ —

	Balance sheet liability fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Collateral posted(c)	Net amount
As of June 30, 2016							
Energy commodity derivative contracts(a)	$(19)	$(47)	$—	$ (66)	$32	$ 18	$ (16)
Interest rate swap agreements	$—	$—	$—	$ —	$—	$ —	$ —
Cross-currency swap agreements	$—	$(34)	$—	$ (34)	$13	$ —	$ (21)
As of December 31, 2015							
Energy commodity derivative contracts(a)	$(4)	$(10)	$(17)	$ (31)	$12	$ —	$ (19)
Interest rate swap agreements	$—	$(25)	$—	$ (25)	$8	$ —	$ (17)
Cross-currency swap agreements	$—	$(52)	$—	$ (52)	$—	$ —	$ (52)

____

(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. Level 3 consists primarily of power derivative contracts.

(b) Cash margin deposits held by us associated with our energy commodity contract positions and OTC swap agreements and reported within “Other current liabilities” on our accompanying consolidated balance sheets.

(c) Cash margin deposits posted by us associated with our energy commodity contract positions and OTC swap agreements and reported within “Other current assets” on our accompanying consolidated balance sheets.

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

Significant unobservable inputs (Level 3)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Derivatives-net asset (liability)				
Beginning of Period	$(2)	$(49)	$(15)	$(61)
Total gains or (losses) included in earnings	(3)	—	(9)	—
Settlements	5	12	24	24
End of Period	$—	$(37)	$—	$(37)
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	$—	$3

As of December 31, 2015, our Level 3 derivative assets and liabilities consisted primarily of power derivative contracts (which expired in April 2016), where a significant portion of fair value is calculated from underlying market data that is not readily observable. The derived values use industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management's best estimate of fair value and management would not expect materially different valuation results were we to use different input amounts within reasonable ranges.

Fair Value of Financial Instruments

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

	June 30, 2016		December 31, 2015	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Total debt	$43,620	$ 43,061	$43,227	$ 37,481

We used Level 2 input values to measure the estimated fair value of our outstanding debt balances as of both June 30, 2016 and December 31, 2015.

7. Reportable Segments

Financial information by segment follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Revenues				
Natural Gas Pipelines				
Revenues from external customers	$1,882	$2,091	$3,852	$4,268
Intersegment revenues	1	5	2	8
CO_2	304	353	606	799
Terminals				
Revenues from external customers	487	469	952	926
Intersegment revenues	1	1	1	1
Products Pipelines				
Revenues from external customers	398	477	789	921
Intersegment revenues	3	1	8	1
Kinder Morgan Canada	63	65	122	125
Other	1	(1)	1	3
Total segment revenues	3,140	3,461	6,333	7,052
Other revenues	9	9	17	18
Less: Total intersegment revenues	(5)	(7)	(11)	(10)
Total consolidated revenues	$3,144	$3,463	$6,339	$7,060

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Segment EBDA(a)				
Natural Gas Pipelines	$966	$928	$1,958	$1,943
CO_2	203	240	389	576
Terminals	292	279	545	549
Products Pipelines	293	277	472	523
Kinder Morgan Canada	40	37	80	78
Other	(5)	(40)	(13)	(46)
Total Segment EBDA	1,789	1,721	3,431	3,623
Total segment DD&A	(552)	(570)	(1,103)	(1,108)
Total segment amortization of excess cost of equity investments	(16)	(14)	(30)	(26)
Other revenues	9	9	17	18
General and administrative expense	(189)	(164)	(379)	(380)
Interest expense, net of unallocable interest income	(470)	(472)	(912)	(986)
Unallocable income tax expense	(196)	(168)	(335)	(380)
Total consolidated net income	$375	$342	$689	$761

	June 30, 2016	December 31, 2015
Assets		
Natural Gas Pipelines	$53,677	$ 53,704
CO_2	4,317	4,706
Terminals	9,673	9,083
Products Pipelines	8,360	8,464
Kinder Morgan Canada	1,586	1,434

Other	317	418
Total segment assets	77,930	77,809
Corporate assets(b)	6,360	6,276
Assets held for sale	27	19
Total consolidated assets	$84,317	$ 84,104

____

23

(a) We evaluate performance based on each segment's EBDA. Segment EBDA includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income), net, and losses on impairments and disposals of long-lived assets, net. Operating expenses include natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes.

(b) Includes cash and cash equivalents, margin and restricted deposits, unallocable interest receivable, prepaid assets and deferred charges, deferred tax assets, risk management assets related to debt fair value adjustments and miscellaneous corporate assets (such as information technology and telecommunications equipment) not allocated to individual 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Income tax expense	$213	$189	$367	$413
Effective tax rate	36.2 %	35.6 %	34.8 %	35.2 %

The effective tax rate for the three months ended June 30, 2016 is 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 Pipeline (Citrus) and Plantation Pipe Line, and the change in the effective state tax rate.

The effective tax rate for the six months ended June 30, 2016 is slightly lower than the statutory federal rate of 35% primarily due to dividend-received deductions from our investment in Citrus and Plantation Pipe Line, and adjustments to our income tax reserve for uncertain tax positions, partially offset by state and foreign income taxes.

The effective tax rate for the three months ended June 30, 2015 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 Citrus.

The effective tax rate for the six months ended June 30, 2015 is marginally 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 Citrus and the change in the effective state tax rate as a result of the Hiland acquisition.

As of June 30, 2016, the total amount of unrecognized tax benefits including interest and penalties relating to uncertain tax positions is $144 million, a decrease of $29 million from the December 31, 2015 balance of $173 million. This $29 million decrease in unrecognized tax benefits resulted primarily from the settlement of a state tax audit and a certain statute of limitations expiration on another matter.

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 are successful in proving these claims or other of their claims, they are entitled to seek reparations (which may reach back up to two years prior to the filing 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. 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 $169 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 several recent FERC decisions in SFPP cases, as applicable, to pending 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. 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 certain intervenors sought judicial review. 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.

Other Commercial Matters

Union Pacific Railroad Company Easements & Related Litigation

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

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

On November 5, 2014, the Court of Appeals issued an opinion which reversed the judgment, including the award of prejudgment interest, and remanded the matter to the trial court for a determination of UPRR's property interest in its right-of-way, including whether UPRR has sufficient interest to grant SFPP's easements. UPRR filed a petition for review to the California Supreme Court which was denied. The trial court has not set a date for the retrial.

After the above-referenced decision by the California Court of Appeals which held that UPRR does not own the subsurface rights to grant certain easements and may not be able to collect rent from those easements, a purported class action lawsuit was filed in 2015 in the U.S. District Court for the Southern District of California by private landowners in California who claim to be the lawful owners of subsurface real property allegedly used or occupied by UPRR or SFPP. Substantially similar follow-on lawsuits were filed and are pending in federal courts by landowners in Nevada, Arizona and New Mexico. These suits, which are brought purportedly as class actions on behalf of all landowners who own land in fee adjacent to and underlying the railroad easement under which the SFPP pipeline is located in those respective states, assert claims against UPRR, SFPP, KMGP, and Kinder Morgan Operating L.P. “D” for declaratory judgment, trespass, ejectment, quiet title, unjust enrichment, accounting, and alleged unlawful business acts and practices arising from defendants’ alleged improper use or occupation of subsurface real property. SFPP views these cases as primarily a dispute between UPRR and the plaintiffs. UPRR purported to grant SFPP a network of subsurface pipeline easements along UPRR’s railroad right-of-way. SFPP relied on the validity of those easements and paid rent to UPRR for the value of those easements. We believe we have recorded a right-of-way liability sufficient to cover our potential obligation, if any, for back rent.

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

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

Gulf LNG Facility Arbitration

On March 1, 2016, Gulf LNG Energy, LLC and Gulf LNG Pipeline, LLC (GLNG) received a Notice of Disagreement and Disputed Statements and a Notice of Arbitration from Eni USA Gas Marketing LLC (Eni USA), one of two companies that entered into a terminal use agreement for capacity of the Gulf LNG Facility in Mississippi for an initial term that is not scheduled to expire until the year 2031. Eni USA is an indirect subsidiary of Eni S.p.A., a multi-national integrated energy company headquartered in Milan, Italy. Pursuant to its Notice of Arbitration, Eni USA seeks declaratory and monetary relief based upon its assertion that (i) the terminal use agreement should be terminated because changes in the U.S. natural gas market since the execution of the agreement in December 2007 have "frustrated the essential purpose" of the agreement and (ii) activities allegedly undertaken by affiliates of Gulf LNG Holdings Group LLC "in connection with a plan to convert the LNG Facility into a liquefaction/export facility have given rise to a contractual right on the part of Eni USA to terminate" the agreement. As set forth in the terminal use agreement, disputes are meant to be resolved by final and binding arbitration. A three-member arbitration panel has been selected and the arbitration hearing is scheduled for January 2017. 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 allegations in the demand for arbitration to be without merit, and we intend to vigorously contest them in the arbitration.

Plains Gas Solutions, LLC v. Tennessee Gas Pipeline Company, L.L.C. et al.

On October 16, 2013, Plains Gas Solutions, LLC (Plains) filed a petition in the 151st Judicial District Court for Harris County, Texas (Case No. 62528) against TGP, Kinetica Partners, LLC and two other Kinetica entities. The suit arises from the sale by TGP of the Cameron System in Louisiana to Kinetica Partners, LLC on September 1, 2013. Plains alleges that defendants breached a straddle agreement requiring that gas on the Cameron System be committed to Plains' Grand Chenier gas-processing facility, that requisite daily volume reports were not provided, that TGP improperly assigned its obligations under the straddle agreement to Kinetica, and that defendants interfered with Plains’ contracts with producers. The petition alleges damages of at least $100 million. Under the Amended and Restated Purchase and Sale Agreement with Kinetica, Kinetica is obligated to defend and indemnify TGP in connection with the gas commitment and reporting claims. After agreeing initially to defend and indemnify TGP against such claims, Kinetica withdrew its defense, disputed its indemnity obligation, and settled with Plains. Trial of the remaining claims against TGP is scheduled for January 2017. We intend to vigorously defend the suit and pursue Kinetica, if necessary, for indemnity and costs of defense.

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

In December 2011 (Brinckerhoff I), March 2012, (Brinckerhoff II), May 2013 (Brinckerhoff III) and June 2014 (Brinckerhoff IV), derivative lawsuits were filed in Delaware Chancery Court against El Paso Corporation, El Paso Pipeline GP

Company, L.L.C., the general partner of EPB, and the directors of the general partner at the time of the relevant transactions. EPB was named in these lawsuits as a "Nominal Defendant." The lawsuits arise from the March 2010, November 2010, May 2012 and June 2011 drop-down transactions involving EPB's purchase of SLNG, Elba Express, CPG and interests in SNG and CIG. The lawsuits allege various conflicts of interest and that the consideration paid by EPB was excessive. Brinckerhoff I and II were consolidated into one proceeding. Motions to dismiss were filed in Brinckerhoff III and Brinckerhoff IV, and such motions remain pending. On June 12, 2014, defendants' motion for summary judgment was granted in Brinckerhoff I, dismissing the case in its entirety. Defendants' motion for summary judgment in Brinckerhoff II was granted in part, dismissing certain claims and allowing the matter to go to trial in late 2014 on the remaining claims. On April 20, 2015, the Court issued a post-trial memorandum opinion (Memorandum Opinion) in Brinckerhoff II entering judgment in favor of all of the defendants other than the general partner of EPB, but finding the general partner liable for breach of contract in connection with EPB's purchase of 49% interests in Elba and SLNG and a 15% interest in SNG in a $1.13 billion drop-down transaction that closed on November 19, 2010 (Fall Dropdown), prior to our acquisition of El Paso Corporation in 2012. In its Memorandum Opinion, the Court determined that EPB suffered damages of $171 million from the Fall Dropdown, which the Court determined to be the amount that EPB overpaid for Elba. We believe the claim is derivative in nature and was extinguished by our acquisition on November 26, 2014, pursuant to a merger agreement, of all of the outstanding common units of EPB that we did not already own. On December 2, 2015, the Court denied our motion to dismiss the remaining claims in Brinckerhoff II based upon our acquisition of all of the outstanding common units of EPB, and held that damages should be calculated by considering the unaffiliated unitholders' ownership percentage as of the effective date of the merger. Based on this ruling, the Court entered judgment on February 4, 2016 in the amount of $100.2 million plus interest at the legal rate for the period from November 15, 2010 until the date of payment, if any payment is ultimately required. We filed an appeal to the Delaware Supreme Court and Brinckerhoff filed a cross-appeal challenging the dismissal of Brinckerhoff I. The appeal has been fully briefed. Execution on the judgment has been stayed until the appeal is decided. At the present time, we do not believe that an ultimate award, if any, will have a material financial impact on our Company. We continue to believe the transactions at issue were appropriate and in the best interests of EPB and we intend to continue to defend the lawsuits vigorously.

Price Reporting Litigation

Beginning in 2003, several lawsuits were filed by purchasers of natural gas against El Paso Corporation, El Paso Marketing L.P. and numerous other energy companies based on a claim under state antitrust law that such defendants conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. Several of the cases have been settled or dismissed. The remaining cases, which were pending in Nevada federal court, were dismissed, but the dismissal was reversed by the 9th Circuit Court of Appeals. The U.S. Supreme Court affirmed the 9th Circuit Court of Appeals in a decision dated April 21, 2015, and the cases were then remanded to the Nevada federal court for further consideration and trial, if necessary, of numerous remaining issues. On May 24, 2016, the Court granted a motion for summary judgment dismissing one of the cases in which approximately $500 million in damages has been alleged. In the remaining cases, approximately $1.5 billion in damages have been alleged against all defendants. There remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, which may be allocated to us. Therefore, our costs and legal exposure related to the remaining outstanding lawsuits and claims are not currently determinable.

Kinder Morgan, Inc. Corporate Reorganization Litigation

Certain unitholders of KMP and EPB filed five putative class action lawsuits in the Court of Chancery of the State of Delaware in connection with the Merger Transactions, which the Court consolidated under the caption In re Kinder Morgan, Inc. Corporate Reorganization Litigation (Consolidated Case No. 10093-VCL). On December 12, 2014, the plaintiffs filed a Verified Second Consolidated Amended Class Action Complaint, which purported to assert claims on behalf of both the former EPB unitholders and the former KMP unitholders. The EPB plaintiff alleged that (i) El Paso Pipeline GP Company, L.L.C. (EPGP), the general partner of EPB, and the directors of EPGP breached duties under the EPB partnership agreement, including the implied covenant of good faith and fair dealing, by entering into the EPB Transaction; (ii) EPB, E Merger Sub LLC, KMI and individual defendants aided and abetted such breaches; and (iii) EPB, E Merger Sub LLC, KMI, and individual defendants tortiously interfered with the EPB partnership agreement by causing EPGP to breach its duties under the EPB partnership agreement.

The KMP plaintiffs alleged that (i) KMR, KMGP, and individual defendants breached duties under the KMP partnership agreement, including the implied duty of good faith and fair dealing, by entering into the KMP Transaction and by failing to adequately disclose material facts related to the transaction; (ii) KMI aided and abetted such breach; and (iii) KMI, KMP, KMR, P Merger Sub LLC, and individual defendants tortiously interfered with the rights of the plaintiffs and the putative class under the KMP partnership agreement by causing KMGP to breach its duties under the KMP partnership agreement. The complaint sought declaratory relief that the transactions were unlawful and unenforceable, reformation, rescission, rescissory or compensatory damages, interest, and attorneys' and experts' fees and costs. On December 30, 2014, the defendants moved to dismiss the complaint. On April 2, 2015, the EPB plaintiff and the defendants submitted a stipulation and proposed order of dismissal, agreeing to dismiss all claims brought by the EPB plaintiff with prejudice as to the EPB lead plaintiff and without prejudice to all other members of the putative EPB class. The Court entered such order on April 2, 2015.

On August 24, 2015, the Court issued an order granting the defendants' motion to dismiss the remaining counts of the complaint for failure to state a claim. On September 21, 2015, plaintiffs filed a notice of appeal to the Supreme Court of the State of Delaware, captioned Haynes Family Trust et al. v. Kinder Morgan G.P., Inc. et al. (Case No. 515). On March 10, 2016, the Delaware Supreme Court affirmed the dismissal of all claims on appeal and this matter is now concluded.

Pipeline Integrity and Releases

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

General

As of June 30, 2016 and December 31, 2015, our total reserve for legal matters was $490 million and $463 million, respectively. The reserve primarily relates to various claims from regulatory proceedings arising in our products and natural gas pipeline segments and certain corporate matters.

Environmental Matters

We and our subsidiaries are subject to environmental cleanup and enforcement actions from time to time. In particular, CERCLA generally imposes joint and several liability for cleanup and enforcement costs on current and predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct, subject to the right of a liable party to establish a "reasonable basis" for apportionment of costs. Our operations are also subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental law 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. As we receive notices of non-compliance, we attempt to negotiate and settle such matters where appropriate. We do not believe that these alleged violations will have a material adverse effect on our business, financial position, results of operations or dividends to our shareholders.

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 includes a combination of dredging, capping, and enhanced natural recovery. It is expected to take approximately 7 years to implement at an estimated present cost of approximately $750 million. Comments on the FS and the Proposed Plan are due on September 7, 2016. We will submit comments with the LWG and on our own behalf. We anticipate the EPA will issue a Record of Decision (ROD) in mid-2017. 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. The allocation process will follow the issuance of the ROD with an expected completion date of 2018. Until the allocation process is completed, we are unable at this time 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 against approximately 70 defendants. On August 6, 2013 plaintiffs filed their Second Amended Complaint seeking monetary damages in unspecified amounts and reducing the number of defendants to 26 including KMEP and SFPP. The claims now presented against KMEP and SFPP are related to alleged releases from a specific parcel within the SFPP Phoenix Terminal and the alleged impact of such releases on water wells owned by the plaintiffs and located in the vicinity of the Terminal. We have filed an answer, general denial, and affirmative defenses in response to the Second Amended Complaint and fact discovery is proceeding.

Mission Valley Terminal Lawsuit

In August 2007, the City of San Diego, on its own behalf and purporting to act on behalf of the People of the State of California, filed a lawsuit against us and several affiliates seeking injunctive relief and unspecified damages allegedly resulting from hydrocarbon and methyl tertiary butyl ether (MTBE) impacted soils and groundwater beneath the City's stadium property in San Diego arising from historic operations at the Mission Valley terminal facility. The case was filed in the Superior Court of California, San Diego County and was removed in 2007 to the U.S. District Court, Southern District of California (Case No. 07CV1883WCAB). The City disclosed in discovery that it was seeking approximately $170 million in damages for alleged lost value/lost profit from the redevelopment of the City's property and alleged lost use of the water resources underlying the property. Later, in 2010, the City amended its initial disclosures to add claims for restoration of the site as well as a number of other claims that increased its claim for damages to approximately $365 million.

On November 29, 2012, the Court issued a Notice of Tentative Rulings on the parties' summary adjudication motions. The Court tentatively granted our partial motions for summary judgment on the City's claims for water and real estate damages and the State's claims for violations of California Business and Professions Code § 17200, tentatively denied the City's motion for summary judgment on its claims of liability for nuisance and trespass, and tentatively granted our cross motion for summary judgment on such claims. On January 25, 2013, the Court rendered judgment in favor of all defendants on all claims asserted by the City.

On February 20, 2013, the City of San Diego filed a notice of appeal to the U.S. Court of Appeals for the Ninth Circuit. On May 21, 2015, the Court of Appeals issued a memorandum decision which affirmed the District Court's summary judgment in our favor with respect to the City's claim under California Safe Drinking Water and Toxic Enforcement Act, but reversed both the District Court's summary judgment decision in our favor on the City's remaining claims and the District Court's decision to exclude the City's expert testimony. The Court of Appeals issued a mandate returning the case to the U.S. District Court. On January 25, 2016, the District Court heard oral argument on motions we previously filed to exclude certain expert testimony offered by the City and for partial summary judgment on the City's claims. By its Order dated February 2, 2016, the Court granted in part and denied in part our motion to exclude certain expert testimony, granted in part and denied in part our motion for partial summary judgment, found that the City is limited to seeking alleged damages relating to the three year period immediately preceding the filing of the lawsuit, found that the City lacks expert opinions or testimony to support its claim for water damages, including the alleged loss of use of the Mission Valley aquifer as a source of both supply and storage of potable water, and denied our motion for partial summary judgment on the City's alleged real estate and restoration damages. As a result of the Court's Order, the City's alleged damages were reduced from approximately $365 million to approximately $160 million. On May 10, 2016, the City filed another lawsuit seeking damages for the three year period immediately preceding the filing of the lawsuit.

On June 17, 2016, the parties entered into a settlement resolving all claims related to the historic contamination at the City's stadium property. The settlement provides for a $20 million payment to the City, a waiver and release by the City of all claims which were asserted or could have been asserted in the litigation, and an agreement by defendants to indemnify the City for additional, incremental costs, if any, incurred by the City in the redevelopment of the stadium property or the development of groundwater beneath the stadium property, that would not have been incurred but for the historical releases from the Mission Valley Terminal. By Order dated June 17, 2016, the District Court granted dismissal of the litigation.

This site remains under the regulatory oversight and order of the California Regional Water Quality Control Board (RWQCB). SFPP completed the soil and groundwater remediation at the City of San Diego's stadium property site and conducted quarterly sampling and monitoring through 2015 as part of the compliance evaluation required by the RWQCB. The RWQCB issued a notice of no further action with respect to the stadium property site on May 4, 2016. SFPP's remediation effort is now focused on its adjacent Mission Valley Terminal site.

Uranium Mines in Vicinity of Cameron, Arizona

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

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

EPEC Polymers, Inc. (EPEC Polymers) and EPEC Oil Company Liquidating Trust (EPEC Oil Trust), former El Paso Corporation entities now owned by KMI, are involved in an administrative action under CERCLA known as the Lower Passaic River Study Area Superfund Site (Site) concerning the lower 17-mile stretch of the Passaic River. It has been alleged that EPEC Polymers and EPEC Oil Trust may be potentially responsible parties (PRPs) under CERCLA based on prior ownership and/or operation of properties located along the relevant section of the Passaic River. EPEC Polymers and EPEC Oil Trust entered into two Administrative Orders on Consent (AOCs) which obligate them to investigate and characterize contamination at the Site. They are also part of a joint defense group (JDG) of approximately 70 cooperating parties which have entered into AOCs and are directing and funding the work required by the EPA. Under the first AOC, draft remedial investigation and feasibility studies (RI/FS) of the Site were submitted to the EPA in 2015, and comments from the EPA are expected by the end of 2016. Under the second AOC, the JDG members conducted a CERCLA removal action at the Passaic River Mile 10.9, and the group is currently conducting EPA-directed post-remedy monitoring in the removal area. We have established a reserve for the anticipated cost of compliance with the AOCs.

On April 11, 2014, the EPA announced the issuance of its Focused Feasibility Study (FFS) for the lower eight miles of the Passaic River Study Area, and its proposed plan for remedial alternatives to address the dioxin sediment contamination from the mouth of Newark Bay to River Mile 8.3. The EPA estimates the cost for the alternatives will range from $365 million to $3.2 billion. The EPA's preferred alternative would involve dredging the river bank-to-bank and installing an engineered cap at an estimated cost of $1.7 billion. On March 4, 2016, the EPA issued its ROD for the lower 8.3 miles of the Passaic River Study area. The final cleanup plan in the ROD is substantially similar to the EPA's preferred alternative announced on April 11, 2014. On March 31, 2016, EPEC Polymers, EPEC Oil Trust, and over 80 other PRPs received a Notice of Potential Liability and Commencement of Negotiations for Remedial Design of the FFS (the Notice). The Notice informed the PRP group that the EPA intends to sign an AOC with one member of the PRP group for the remedial design of the cleanup in the ROD, and initiate negotiations over cash buyouts with parties whom the EPA does not consider "major PRPs." The Notice also stated that the EPA expects to have the remedial design AOC signed by August 31, 2016.

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.

Central Florida Pipeline Release, Tampa, Florida

On July 22, 2011, our subsidiary Central Florida Pipeline LLC (CFPL) reported a refined petroleum products release on a section of its 10-inch diameter pipeline near Tampa, Florida. The pipeline carries jet fuel and diesel to Orlando and was carrying jet fuel at the time of the incident. There was no fire and no injuries associated with the incident. CFPL cleaned up the release in coordination with federal, state and local agencies. The cause of the incident was determined to be a third party line strike. In August 2015, the EPA requested that CFPL engage in settlement discussions regarding potential penalties sought by the EPA under the Clean Water Act. Although CFPL does not believe it caused the incident, we engaged in good faith settlement negotiations with the EPA. In June 2016, the parties filed a joint stipulation of settlement in federal court, resolving the matter for $0.5 million.

Southeast Louisiana Flood Protection Litigation

On July 24, 2013, the Board of Commissioners of the Southeast Louisiana Flood Protection Authority - East (SLFPA) filed a petition for damages and injunctive relief in state district court for Orleans Parish, Louisiana (Case No. 13-6911) against TGP, SNG and approximately 100 other energy companies, alleging that defendants’ drilling, dredging, pipeline and industrial operations since the 1930’s have caused direct land loss and increased erosion and submergence resulting in alleged increased storm surge risk, increased flood protection costs and unspecified damages to the plaintiff. The SLFPA asserts claims for negligence, strict liability, public nuisance, private nuisance, and breach of contract. Among other relief, the petition seeks unspecified monetary damages, attorney fees, interest, and injunctive relief in the form of abatement and restoration of the alleged coastal land loss including but not limited to backfilling and re-vegetation of canals, wetlands and reef creation, land bridge construction, hydrologic restoration, shoreline protection, structural protection, and bank stabilization. On August 13, 2013, the suit was removed to the U.S. District Court for the Eastern District of Louisiana. On February 13, 2015, the Court granted defendants’ motion to dismiss the suit for failure to state a claim, and issued an order dismissing the SLFPA’s claims with prejudice. The SLFPA filed a notice of appeal on February 20, 2015. The U.S. Court of Appeals for the Fifth Circuit heard oral argument on February 29, 2016 and we await the Court’s decision.

Plaquemines Parish Louisiana Coastal Zone Litigation

On November 8, 2013, the Parish of Plaquemines, Louisiana filed a petition for damages in the state district court for Plaquemines Parish, Louisiana (Docket No. 60-999) against TGP and 17 other energy companies, alleging that defendants’ oil and gas exploration, production and transportation operations in the Bastian Bay, Buras, Empire and Fort Jackson oil and gas fields of Plaquemines Parish caused substantial damage to the coastal waters and nearby lands (Coastal Zone) within the Parish, including the erosion of marshes and the discharge of oil waste and other pollutants which detrimentally affected the quality of state waters and plant and animal life, in violation of the State and Local Coastal Resources Management Act of 1978 (Coastal Zone Management Act). As a result of such alleged violations of the Coastal Zone Management Act, Plaquemines Parish seeks, among other relief, unspecified monetary relief, attorney fees, interest, and payment of costs necessary to restore the allegedly affected Coastal Zone to its original condition, including costs to clear, vegetate and detoxify the Coastal Zone. In connection with this suit, TGP has made two tenders for defense and indemnity: (1) to Anadarko, as successor to the entity that purchased TGP’s oil and gas assets in Bastian Bay, and (2) to Kinetica, which purchased TGP’s pipeline assets in Bastian Bay in 2013. Anadarko has accepted TGP’s tender (limited to oil and gas assets), and Kinetica rejected TGP’s tender. TGP responded to Kinetica by reasserting TGP’s demand for defense and indemnity and reserving its rights. On November 12, 2015, the Plaquemines Parish Council adopted a resolution directing its legal counsel in all its Coastal Zone cases to take all actions necessary to cause the dismissal of all such cases. By the end of 2015, the Parish’s legal counsel had not taken any action to dismiss the cases, and the defendants in the cases, including TGP in the instant case, filed motions to dismiss on the basis of the Parish Council’s November 12, 2015 resolution. After the filing of the motions to dismiss, the Louisiana Department of Natural Resources and Attorney General filed petitions in intervention. On April 14, 2016, the Parish Council passed a resolution rescinding its November 12, 2015 resolution that had directed its counsel to dismiss the suit. This resolution renders moot our pending motion to dismiss. We intend to continue 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 June 30, 2016 and December 31, 2015, we have accrued a total reserve for environmental liabilities in the amount of $318 million and $284 million, respectively. In addition, as of both June 30, 2016 and December 31, 2015, we have recorded a receivable of $13 million, for expected cost recoveries that have been deemed probable.

10. Recent Accounting Pronouncements

ASU No. 2014-09

On May 28, 2014, the FASB issued ASU Nos. 2014-09, “Revenue from Contracts with Customers (Topic 606).” This ASU is designed to create greater comparability for financial statement users across industries and jurisdictions. The provisions of ASU No. 2014-09 include a five-step process by which entities will recognize revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which an entity expects to be entitled in exchange for those goods or services. The standard also will require enhanced disclosures, provide more comprehensive guidance for transactions such as service revenue and contract modifications, and enhance guidance for multiple-element arrangements. ASU No. 2014-09 will be effective for us as of January 1, 2018. Early adoption is permitted for the interim periods within the adoption year. We are currently reviewing the effect of this ASU on our revenue recognition and assessing the timing of our adoption.

ASU No. 2015-02
On February 18, 2015, the FASB issued ASU No. 2015-02, “Consolidation (Topic 810) - Amendments to the Consolidated Analysis.” This ASU focuses on the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities. We adopted ASU No. 2015-02 effective January 1, 2016 with no material impact to our financial statements.

ASU No. 2015-11

On July 22, 2015, the FASB issued ASU No. 2015-11, “Inventory (Topic 330): Simplifying the Measurement of Inventory.” This ASU requires entities to subsequently measure inventory at the lower of cost and net realizable value, and defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. ASU No. 2015-11 will be effective for us as of January 1, 2017. We are currently reviewing the effect of ASU No. 2015-11.

ASU No. 2016-02

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

ASU No. 2016-05

On March 10, 2016, the FASB issued ASU 2016-05, “Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships.” This ASU clarifies that for the purposes of applying the guidance in Topic 815, a change in the counterparty to a derivative instrument that has been designated as the hedging instrument in an existing hedging relationship would not, in and of itself, be considered a termination of the derivative instrument. We adopted ASU 2016-05 in the first quarter of 2016 with no material impact to our financial statements.

ASU No. 2016-09

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

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.

11. Guarantee of Securities of Subsidiaries

KMI, along with its direct and indirect subsidiaries KMP and Copano, are issuers of certain public debt securities. After the completion of the Merger Transactions, KMI, KMP, Copano and substantially all of KMI’s wholly owned domestic subsidiaries, entered into 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 issuers 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, KMP or Copano are in the same position with respect to the net assets, income and cash flows of KMI and the Subsidiary Issuers 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 each 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 issuers in separate columns in this single set of condensed consolidating financial statements.

Excluding fair value adjustments, as of June 30, 2016, Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, Subsidiary Issuer and Guarantor-Copano, and Subsidiary Guarantors had $15,032 million, $19,485 million, $332 million, and $5,783 million, respectively, of Guaranteed Notes outstanding. Included in the Subsidiary Guarantors debt balance as presented in the accompanying June 30, 2016 condensed consolidating balance sheets is approximately $173 million of capitalized lease debt that is not subject to the cross guarantee agreement.

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

Effective December 31, 2015, Kinder Morgan (Delaware), Inc. and Kinder Morgan Services LLC merged into KMI. As a result of such merger, both entities are no longer Subsidiary Guarantors, and for all periods presented, financial statement balances and activities for Kinder Morgan (Delaware), Inc. and Kinder Morgan Services LLC are reflected within the Parent Issuer and Guarantor column.

Condensed Consolidating Statements of Income and Comprehensive Income
for the Three Months Ended June 30, 2016
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 8	$ —	$ —	$ 2,777	$ 371	$ (12)	$ 3,144
Operating Costs, Expenses and Other							
Costs of sales	—	—	—	693	60	(1)	752
Depreciation, depletion and amortization	4	—	—	462	86	—	552
Other operating expenses	30	2	—	681	198	(11)	900
Total Operating Costs, Expenses and Other	34	2	—	1,836	344	(12)	2,204
Operating (loss) income	(26)	(2)	—	941	27	—	940
Other Income (Expense)							
Earnings (losses) from consolidated subsidiaries	752	734	(3)	41	17	(1,541)	—
Earnings from equity investments	—	—	—	106	—	—	106
Interest, net	(176)	34	(12)	(304)	(13)	—	(471)
Amortization of excess cost of equity investments and other, net	1	—	—	6	6	—	13
Income (Loss) Before Income Taxes	551	766	(15)	790	37	(1,541)	588
Income Tax Expense	(179)	(1)	—	(16)	(17)	—	(213)
Net Income (Loss)	372	765	(15)	774	20	(1,541)	375
Net Income Attributable to Noncontrolling Interests	—	—	—	—	—	(3)	(3)
Net Income (Loss) Attributable to Controlling Interests	372	765	(15)	774	20	(1,544)	372
Preferred Stock Dividends	(39)	—	—	—	—	—	(39)
Net Income (Loss) Available to Common Stockholders	$ 333	$ 765	$ (15)	$ 774	$ 20	$ (1,544)	$ 333
Net Income (loss)	$ 372	$ 765	$ (15)	$ 774	$ 20	$ (1,541)	$ 375
Total other comprehensive (loss) income	(140)	(213)	—	(223)	8	428	(140)
Comprehensive income (loss)	232	552	(15)	551	28	(1,113)	235
Comprehensive income attributable to noncontrolling interests	—	—	—	—	—	(3)	(3)

Comprehensive income (loss) attributable to controlling interests	$ 232	$ 552	$ (15)	$ 551	$ 28	$ (1,116)	$ 232

34

Condensed Consolidating Statements of Income and Comprehensive Income
for the Three Months Ended June 30, 2015
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 10	$ —	$ —	$ 3,050	$ 414	$ (11)	$ 3,463
Operating Costs, Expenses and Other							
Costs of sales	—	—	—	989	95	1	1,085
Depreciation, depletion and amortization	5	—	—	473	92	—	570
Other operating expenses	38	—	—	767	123	(12)	916
Total Operating Costs, Expenses and Other	43	—	—	2,229	310	(11)	2,571
Operating (loss) income	(33)	—	—	821	104	—	892
Other Income (Expense)							
Earnings (losses) from consolidated subsidiaries	683	666	(5)	127	15	(1,486)	—
Earnings from equity investments	—	—	—	114	—	—	114
Interest, net	(149)	34	(12)	(345)	—	—	(472)
Amortization of excess cost of equity investments and other, net	—	—	—	(5)	2	—	(3)
Income (Loss) Before Income Taxes	501	700	(17)	712	121	(1,486)	531
Income Tax Expense	(168)	(2)	—	(11)	(8)	—	(189)
Net Income (Loss)	333	698	(17)	701	113	(1,486)	342
Net Income Attributable to Noncontrolling Interests	—	—	—	—	—	(9)	(9)
Net Income (Loss) Attributable to Controlling Interests	$ 333	$ 698	$ (17)	$ 701	$ 113	$ (1,495)	$ 333
Net Income (loss)	$ 333	$ 698	$ (17)	$ 701	$ 113	$ (1,486)	$ 342
Total other comprehensive (loss) income	(98)	(139)	—	(148)	23	264	(98)
Comprehensive income (loss)	235	559	(17)	553	136	(1,222)	244
Comprehensive income attributable to noncontrolling interests	—	—	—	—	—	(9)	(9)
Comprehensive income (loss) attributable to controlling interests	$ 235	$ 559	$ (17)	$ 553	$ 136	$ (1,231)	$ 235

Condensed Consolidating Statements of Income and Comprehensive Income
for the Six Months Ended June 30, 2016
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 17	$ —	$ —	$ 5,602	$ 741	$ (21)	$ 6,339
Operating Costs, Expenses and Other							
Costs of sales	—	—	—	1,345	136	2	1,483
Depreciation, depletion and amortization	9	—	—	918	176	—	1,103
Other operating expenses	49	4	—	1,494	473	(23)	1,997
Total Operating Costs, Expenses and Other	58	4	—	3,757	785	(21)	4,583
Operating (loss) income	(41)	(4)	—	1,845	(44)	—	1,756
Other Income (Expense)							
Earnings from consolidated subsidiaries	1,410	1,331	4	54	31	(2,830)	—
Earnings from equity investments	—	—	—	200	—	—	200
Interest, net	(346)	97	(24)	(613)	(26)	—	(912)
Amortization of excess cost of equity investments and other, net	1	—	—	1	10	—	12
Income (Loss) Before Income Taxes	1,024	1,424	(20)	1,487	(29)	(2,830)	1,056
Income Tax Expense	(337)	(3)	—	(10)	(17)	—	(367)
Net Income (Loss)	687	1,421	(20)	1,477	(46)	(2,830)	689
Net Income Attributable to Noncontrolling Interests	—	—	—	—	—	(2)	(2)
Net Income (Loss) Attributable to Controlling Interests	687	1,421	(20)	1,477	(46)	(2,832)	687
Preferred Stock Dividends	(78)	—	—	—	—	—	(78)
Net Income (Loss) Available to Common Stockholders	$ 609	$ 1,421	$ (20)	$ 1,477	$ (46)	$ (2,832)	$ 609
Net Income (loss)	$ 687	$ 1,421	$ (20)	$ 1,477	$ (46)	$ (2,830)	$ 689
Total other comprehensive (loss) income	(93)	(161)	—	(229)	132	258	(93)
Comprehensive income (loss)	594	1,260	(20)	1,248	86	(2,572)	596
	—	—	—	—	—	(2)	(2)

Comprehensive income attributable to noncontrolling interests							
Comprehensive income (loss) attributable to controlling interests	$ 594	$ 1,260	$ (20)	$ 1,248	$ 86	$ (2,574)	$ 594

Condensed Consolidating Statements of Income and Comprehensive Income
for the Six Months Ended June 30, 2015
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 19	$ —	$ —	$ 6,276	$ 789	$ (24)	$ 7,060
Operating Costs, Expenses and Other							
Costs of sales	—	—	—	1,990	184	1	2,175
Depreciation, depletion and amortization	10	—	—	915	183	—	1,108
Other operating expenses	50	38	1	1,452	291	(25)	1,807
Total Operating Costs, Expenses and Other	60	38	1	4,357	658	(24)	5,090
Operating (loss) income	(41)	(38)	(1)	1,919	131	—	1,970
Other Income (Expense)							
Earnings (loss) from consolidated subsidiaries	1,482	1,549	(28)	141	31	(3,175)	—
Earnings from equity investments	—	—	—	190	—	—	190
Interest, net	(304)	7	(24)	(649)	(14)	—	(984)
Amortization of excess cost of equity investments and other, net	—	—	—	(8)	6	—	(2)
Income (Loss) Before Income Taxes	1,137	1,518	(53)	1,593	154	(3,175)	1,174
Income Tax Expense	(375)	(4)	—	(25)	(9)	—	(413)
Net Income (Loss)	762	1,514	(53)	1,568	145	(3,175)	761
Net Loss Attributable to Noncontrolling Interests	—	—	—	—	—	1	1
Net Income (Loss) Attributable to Controlling Interests	762	1,514	(53)	1,568	145	(3,174)	762
Net Income (loss)	$ 762	$ 1,514	$ (53)	$ 1,568	$ 145	$ (3,175)	$ 761
Total other comprehensive loss	(274)	(377)	—	(344)	(141)	862	(274)
Comprehensive income (loss)	488	1,137	(53)	1,224	4	(2,313)	487
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	—	1	1
Comprehensive income (loss) attributable to controlling interests	$ 488	$ 1,137	$ (53)	$ 1,224	$ 4	$ (2,312)	$ 488

37

Condensed Consolidating Balance Sheets as of June 30, 2016
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS							
Cash and cash equivalents	$ 8	$ —	$ —	$ 11	$ 168	$ (7)	$ 180
Other current assets - affiliates	5,859	6,192	115	13,171	745	(26,082)	—
All other current assets	141	186	—	1,787	184	(8)	2,290
Property, plant and equipment, net	270	—	—	32,366	8,563	—	41,199
Investments	16	2	—	6,062	122	—	6,202
Investments in subsidiaries	25,221	25,762	2,345	4,926	3,973	(62,227)	—
Goodwill	15,089	22	287	5,220	3,184	—	23,802
Notes receivable from affiliates	1,024	21,741	—	1,239	319	(24,323)	—
Deferred income taxes	7,211	—	—	—	—	(2,236)	4,975
Other non-current assets	373	537	1	4,646	112	—	5,669
Total assets	$ 55,212	$ 54,442	$ 2,748	$ 69,428	$ 17,370	$ (114,883)	$ 84,317
LIABILITIES AND STOCKHOLDERS' EQUITY							
Liabilities							
Current portion of debt	$ 1,510	$ 600	$ —	$ 1,187	$ 122	$ —	$ 3,419
Other current liabilities - affiliates	1,788	14,623	51	9,133	487	(26,082)	—
All other current liabilities	373	481	7	1,831	470	(15)	3,147
Long-term debt	14,226	19,662	374	5,260	679	—	40,201
Notes payable to affiliates	1,547	448	753	20,217	1,358	(24,323)	—
Deferred income taxes	—	—	2	625	1,609	(2,236)	—
All other long-term liabilities and deferred credits	657	70	—	889	461	—	2,077
Total liabilities	20,101	35,884	1,187	39,142	5,186	(52,656)	48,844
Stockholders' equity							
Total KMI equity	35,111	18,558	1,561	30,286	12,184	(62,589)	35,111
Noncontrolling interests	—	—	—	—	—	362	362
Total stockholders' Equity	35,111	18,558	1,561	30,286	12,184	(62,227)	35,473
Total Liabilities and Stockholders' Equity	$ 55,212	$ 54,442	$ 2,748	$ 69,428	$ 17,370	$ (114,883)	$ 84,317

38

Condensed Consolidating Balance Sheets as of December 31, 2015
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS							
Cash and cash equivalents	$ 123	$ —	$ —	$ 12	$ 142	$ (48)	$ 229
Other current assets - affiliates	2,233	1,600	—	9,451	695	(13,979)	—
All other current assets	126	119	—	2,163	195	(8)	2,595
Property, plant and equipment, net	252	—	—	32,195	8,100	—	40,547
Investments	16	2	—	5,906	116	—	6,040
Investments in subsidiaries	27,401	28,038	2,341	4,361	3,320	(65,461)	—
Goodwill	15,089	22	287	5,221	3,171	—	23,790
Notes receivable from affiliates	850	21,319	—	2,070	380	(24,619)	—
Deferred income taxes	7,501	—	—	—	—	(2,178)	5,323
Other non-current assets	215	307	1	4,943	114	—	5,580
Total assets	$ 53,806	$ 51,407	$ 2,629	$ 66,322	$ 16,233	$ (106,293)	$ 84,104
LIABILITIES AND STOCKHOLDERS' EQUITY							
Liabilities							
Current portion of debt	$ 67	$ 500	$ —	$ 132	$ 122	$ —	$ 821
Other current liabilities - affiliates	1,328	8,682	39	3,216	714	(13,979)	—
All other current liabilities	321	458	7	1,987	527	(56)	3,244
Long-term debt	13,845	20,053	378	7,447	683	—	42,406
Notes payable to affiliates	2,404	448	622	19,840	1,305	(24,619)	—
Deferred income taxes	—	—	2	594	1,582	(2,178)	—
Other long-term liabilities and deferred credits	722	193	—	907	408	—	2,230
Total liabilities	18,687	30,334	1,048	34,123	5,341	(40,832)	48,701
Stockholders' equity							
Total KMI equity	35,119	21,073	1,581	32,199	10,892	(65,745)	35,119
Noncontrolling interests	—	—	—	—	—	284	284
Total stockholders' Equity	35,119	21,073	1,581	32,199	10,892	(65,461)	35,403
Total Liabilities and Stockholders' Equity	$ 53,806	$ 51,407	$ 2,629	$ 66,322	$ 16,233	$ (106,293)	$ 84,104

39

Condensed Consolidating Statements of Cash Flows for the Six Months Ended June 30, 2016
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	$ (1,950)	$ 2,976	$ (143)	$ 5,616	$ 221	$ (4,376)	$ 2,344
Cash flows from investing activities							
Funding to affiliates	(1,670)	(770)	(1)	(2,455)	(219)	5,115	—
Capital expenditures	(37)	—	—	(929)	(504)	—	(1,470)
Contributions to investments	(343)	—	—	(13)	(7)	—	(363)
Acquisitions of assets and investments, net of cash acquired	(2)	—	—	(331)	—	—	(333)
Sale of property, plant and equipment, investments and other net assets, net of removal costs	—	—	—	220	—	—	220
Distributions from equity investments in excess of cumulative earnings	1,443	298	—	68	—	(1,728)	81
Other, net	—	(54)	—	37	2	—	(15)
Net cash used in investing activities	(609)	(526)	(1)	(3,403)	(728)	3,387	(1,880)
Cash flows from financing activities							
Issuances of debt	6,847	—	—	—	—	—	6,847
Payments of debt	(5,191)	(500)	—	(1,104)	(5)	—	(6,800)
Funding from affiliates	1,429	882	144	2,124	536	(5,115)	—
Debt issue costs	(6)	—	—	—	—	—	(6)
Cash dividends - common shares	(559)	—	—	—	—	—	(559)
Cash dividends - preferred shares	(76)	—	—	—	—	—	(76)
Contributions from parents	—	—	—	—	87	(87)	—
Contributions from noncontrolling interests	—	—	—	—	—	87	87
Distributions to parents	—	(2,832)	—	(3,234)	(90)	6,156	—
Distributions to noncontrolling interests	—	—	—	—	—	(11)	(11)
Net cash provided by (used in) financing activities	2,444	(2,450)	144	(2,214)	528	1,030	(518)
Effect of exchange rate changes on cash and cash equivalents	—	—	—	—	5	—	5
Net (decrease) increase in cash and cash equivalents	(115)	—	—	(1)	26	41	(49)
Cash and cash equivalents, beginning of period	123	—	—	12	142	(48)	229
	$ 8	$ —	$ —	$ 11	$ 168	$ (7)	$ 180

Cash and cash equivalents, end of period	

40

Condensed Consolidating Statements of Cash Flows for the Six Months Ended June 30, 2015
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	$ (1,147)	$ 5,190	$ 72	$ 3,755	$ (26)	$ (5,306)	$ 2,538
Cash flows from investing activities							
Funding to affiliates	(2,118)	(6,486)	(1)	(4,387)	(351)	13,343	—
Capital expenditures	(23)	—	(3)	(1,705)	(183)	5	(1,909)
Contributions to investments	—	—	—	(45)	—	—	(45)
Investment in KMP	(159)	—	—	—	—	159	—
Acquisitions of assets and investments, net of cash acquired	(1,709)	—	—	(210)	—	—	(1,919)
Sale of property, plant and equipment, investments and other net assets, net of removal costs	—	—	5	4	—	(5)	4
Distributions from equity investments in excess of cumulative earnings	292	—	—	80	—	(258)	114
Other, net	—	(2)	—	4	9	—	11
Net cash (used in) provided by investing activities	(3,717)	(6,488)	1	(6,259)	(525)	13,244	(3,744)
Cash flows from financing activities							
Issuances of debt	9,485	—	—	—	—	—	9,485
Payments of debt	(8,598)	(300)	—	(38)	(5)	—	(8,941)
Funding from (to) affiliates	3,471	3,906	(73)	5,546	493	(13,343)	—
Debt issue costs	(20)	—	—	—	—	—	(20)
Issuances of common shares	2,562	—	—	—	—	—	2,562
Cash dividends	(2,006)	—	—	—	—	—	(2,006)
Repurchases of warrants	(5)	—	—	—	—	—	(5)
Contributions from parents	—	156	—	3	—	(159)	—
Distributions to parents	—	(2,478)	—	(3,010)	(92)	5,580	—
Distributions to noncontrolling interests	—	—	—	—	—	(16)	(16)
Other, net	—	(1)	—	—	—	—	(1)
Net cash provided by (used in) financing activities	4,889	1,283	(73)	2,501	396	(7,938)	1,058
Effect of exchange rate changes on cash and cash equivalents	—	—	—	—	(4)	—	(4)
Net increase (decrease) in cash and cash equivalents	25	(15)	—	(3)	(159)	—	(152)
	4	15	—	17	279	—	315

Cash and cash equivalents, beginning of period							
Cash and cash equivalents, end of period	$ 29	$ —	$ —	$ 14	$ 120	$ —	$ 163

41

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 2015 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 interest expense, general and administrative expenses, and unallocable interest income and income taxes, as well as net income attributable to noncontrolling interests. 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.

Consolidated Earnings Results

	Three Months Ended June 30,			
	2016	2015	Earnings increase/(decrease)	
	(In millions, except percentages)			
Segment EBDA(a)				
Natural Gas Pipelines	$966	$928	$ 38	4 %
CO_2	203	240	(37)	(15)%
Terminals	292	279	13	5 %
Products Pipelines	293	277	16	6 %
Kinder Morgan Canada	40	37	3	8 %
Other	(5)	(40)	35	88 %
Total Segment EBDA(b)	1,789	1,721	68	4 %
DD&A expense	(552)	(570)	18	3 %
Amortization of excess cost of equity investments	(16)	(14)	(2)	(14)%
Other revenues	9	9	—	— %
General and administrative expense(c)	(189)	(164)	(25)	(15)%
Interest expense, net of unallocable interest income(d)	(470)	(472)	2	— %
Income before unallocable income taxes	571	510	61	12 %
Unallocable income tax expense	(196)	(168)	(28)	(17)%
Net income	375	342	33	10 %
Net income attributable to noncontrolling interests	(3)	(9)	6	67 %
Net income attributable to Kinder Morgan, Inc.	372	333	39	12 %
Preferred Stock Dividends	(39)	—	(39)	n/a
Net income available to common stockholders	$333	$333	$ —	— %

42

	Six Months Ended June 30, 2016	2015	Earnings increase/(decrease)	
	(In millions, except percentages)			
Segment EBDA(a)				
Natural Gas Pipelines	$1,958	$1,943	$ 15	1 %
CO_2	389	576	(187)	(32)%
Terminals	545	549	(4)	(1)%
Products Pipelines	472	523	(51)	(10)%
Kinder Morgan Canada	80	78	2	3 %
Other	(13)	(46)	33	72 %
Total Segment EBDA(b)	3,431	3,623	(192)	(5)%
DD&A expense	(1,103)	(1,108)	5	— %
Amortization of excess cost of equity investments	(30)	(26)	(4)	(15)%
Other revenues	17	18	(1)	(6)%
General and administrative expense(c)	(379)	(380)	1	— %
Interest expense, net of unallocable interest income(d)	(912)	(986)	74	8 %
Income before unallocable income taxes	1,024	1,141	(117)	(10)%
Unallocable income tax expense	(335)	(380)	45	12 %
Net income	689	761	(72)	(9)%
Net (income) loss attributable to noncontrolling interests	(2)	1	(3)	(300)%
Net income attributable to Kinder Morgan, Inc.	687	762	(75)	(10)%
Preferred Stock Dividends	(78)	—	(78)	n/a
Net income available to common stockholders	$609	$762	$ (153)	(20)%

n/a – not applicable

(a) Includes revenues, earnings from equity investments, allocable interest income and other, net, less operating expenses, allocable income taxes, other expense (income), net, losses on impairments and disposals of long-lived assets, net. Operating expenses include natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes. Allocable income tax expenses included in Segment EBDA for the three months ended June 30, 2016 and 2015 were $17 million and $21 million, respectively, and for the six months ended June 30, 2016 and 2015 were $32 million and $33 million, respectively.

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

(b) Three and six month 2016 amounts include net decreases in earnings of $7 million and $305 million, respectively, and three and six month 2015 amounts include decreases in earnings of $106 million and $116 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) Three and six month 2016 amounts include net increases in expense of $22 million and $28 million, respectively, and three and six month 2015 amounts include a decrease in expense of $9 million and an increase in expense of $29 million, respectively, related to the combined effect of the certain items related to general and administrative expense disclosed below in "—General and Administrative, Interest, and Noncontrolling Interests."

(d) Three and six month 2016 amounts include net decreases in expense of $40 million and $109 million, respectively, and three and six month 2015 amounts include decreases in expense of $55 million for both respective periods, related to the combined effect of the certain items related to interest expense, net of unallocable interest income disclosed below in "—General and Administrative, Interest, and Noncontrolling Interests."

The certain item totals reflected in footnotes (b), (c) and (d) to the tables above accounted for $53 million of the increase in income before unallocable income taxes for the second quarter of 2016, as compared to the same prior year period (representing the difference between increases of $11 million and decreases $42 million in income before unallocable income taxes for the second quarters of 2016 and 2015, respectively) and a decrease of $134 million in income before unallocable income taxes for the six months ended June 30, 2016, when compared to the same prior year period (representing the difference between decreases of $224 million and $90 million in income before unallocable income taxes for the six months ended June 30, 2016 and 2015, respectively). After giving effect to these certain items, the remaining increases in income before unallocable income taxes from the prior year quarter and year-to-date were $8 million (1%) and $17 million (1%), respectively. The quarter-to-date increase from 2015 reflects decreased interest expense, net of allocable interest income, DD&A expense and general and administrative expense increased results in our Products Pipelines and Terminals business segments, mostly offset by unfavorable commodity prices affecting our CO2 business segment. The year-to-date increase from 2015 reflects decreased interest expense, net of allocable interest income by increased results in our Products Pipelines, Natural Gas Pipelines and Terminals business segments, mostly offset by unfavorable commodity prices affecting our CO2 business segment.

Non-GAAP Measures

Our non-GAAP financial measures are DCF and Segment EBDA before certain items. Certain items are items that are required by GAAP to be reflected in net income, but typically either do not have a cash impact, or by their nature are separately identifiable from our normal business operations and, in our view, are likely to occur only sporadically.

Our non-GAAP measures described below should not be considered as an alternative to GAAP net income available to common stockholders or any other GAAP measure. DCF and Segment EBDA before certain items are not financial measures in accordance with GAAP and have important limitations as analytical tools. You should not consider either of these non-GAAP measures in isolation or as a substitute for an analysis of our results as reported under GAAP. Because DCF excludes some but not all items that affect net income available to common stockholders and because DCF measures are defined differently by different companies in our industry, our DCF may not be comparable to DCF measures of other companies. Our computation of Segment EBDA before certain items has similar limitations. Management compensates for the limitations of these non-GAAP measures by reviewing our comparable GAAP measures, understanding the differences between the measures and taking this information into account in its analysis and its decision making processes.

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 dividends, stock repurchases, retirement of debt or expansion capital expenditures. Management uses this measure and believes it provides users of our financial statements a measure that more accurately reflects our business' ability to generate cash earnings than a comparable GAAP measure. For a discussion of our anticipated dividends for 2016, see "Liquidity and Capital Resources—Common Dividends."

Segment EBDA Before Certain Items

We believe Segment EBDA before certain items is a significant performance metric because it enables us and external users of our financial statements to better understand the ability of our segments to generate cash earnings on an ongoing basis. We believe it is useful to investors because it is a measure that management uses to allocate resources to our segments and assess each segment's performance. Intersegment sales accounted for at market prices, are eliminated in consolidation.

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 June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Net Income Available to Common Stockholders	$333	$333	$609	$762
Add/(Subtract):				
Certain items before book tax(a)	(9)	42	226	90
Book tax certain items(b)	1	(19)	(102)	(41)
Certain items after book tax	(8)	23	124	49
Noncontrolling interest certain items(c)	(3)	1	(9)	(14)
Net income available to common stockholders before certain items	322	357	724	797
Add/(Subtract):				
DD&A expense(d)	656	662	1,308	1,296
Total book taxes(e)	236	227	515	489
Cash taxes(f)	(37)	(18)	(39)	(16)
Other items(g)	10	8	20	16
Sustaining capital expenditures(h)	(137)	(141)	(245)	(245)
DCF	$1,050	$1,095	$2,283	$2,337
Weighted average common shares outstanding for dividends(i)	2,237	2,194	2,237	2,177
DCF per common share	$0.47	$0.50	$1.02	$1.07
Declared dividend per common share	$0.125	$0.490	$0.250	$0.970

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

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

(c) Represents noncontrolling interests share of certain items.

(d) Includes DD&A and amortization of excess cost of equity investments. Three and six month 2016 amounts also include $88 million and $175 million, respectively, and three and six month 2015 amounts also include $78 million and $162 million, respectively, of our share of equity investees' DD&A.

(e) Excludes book tax certain items and includes income tax allocated to the segments. Three and six month 2016 amounts also include $24 million and $46 million, respectively, and three and six month 2015 amounts also include $19 million and $35 million, respectively, of our share of taxable equity investees' book tax expense.

(f) Three and six month 2016 amounts include $(30) million and $(34) million, respectively, and three and six month 2015 amounts include $(7) million and $(6) million, respectively, of our share of taxable equity investees' cash taxes.

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

(h) Three and six month 2016 amounts include $(20) million and $(42) million, respectively, and three and six month 2015 amounts include $(16) million and $(34) million, respectively, of our share of equity investees' sustaining capital expenditures.

(i) Includes restricted stock awards that participate in common share dividends and dilutive effect of warrants, as applicable.

45

Segment Earnings Results

Natural Gas Pipelines

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In millions, except operating statistics)			
Revenues(a)	$1,883	$2,096	$3,854	$4,276
Operating expenses	(1,004)	(1,227)	(1,943)	(2,399)
Loss on impairments and disposals of long-lived assets, net(b)	(5)	(39)	(121)	(92)
Other income	—	3	—	3
Earnings from equity investments(b)	84	92	156	147
Interest income and Other, net	9	5	15	12
Income tax expense	(1)	(2)	(3)	(4)
Segment EBDA(b)	966	928	1,958	1,943
Certain items(b)	(8)	37	130	109
Segment EBDA before certain items	$958	$965	$2,088	$2,052

Change from prior period	Increase/(Decrease)			
Revenues before certain items	$(228)	(11)%	$(423)	(10)%
Segment EBDA before certain items	$(7)	(1)%	$36	2 %

Natural gas transport volumes (BBtu/d)(c)	28,728	27,764	29,560	29,303
Natural gas sales volumes (BBtu/d)(d)	2,281	2,408	2,306	2,402
Natural gas gathering volumes (BBtu/d)(e)	2,993	3,573	3,100	3,560
Crude/condensate gathering volumes (MBbl/d)(f)	304	346	324	338

____

Certain items affecting Segment EBDA

(a) Three and six month 2016 amounts include decreases in revenue of $26 million and $32 million, respectively, and three and six month 2015 amounts include a decrease in revenue of $2 million and an increase in revenue of $6 million, respectively, related to non-cash mark-to-market derivative contracts used to hedge forecasted natural gas, NGL and crude oil sales. Three and six month 2016 amounts also include increases in revenue of $39 million for both periods associated with revenue collected on a customer's early buyout of a long-term natural gas storage contract.

(b) In addition to the revenue certain items described in footnote (a) above: three and six month 2016 amounts also include decreases in earnings of $5 million and $16 million, respectively, related to losses on impairments and disposals of other assets, and six month 2016 amount also includes decreases in earnings of (i) $106 million of project write-offs; (ii) $13 million related to an equity investment impairment; and (iii) $2 million from other certain items, and three and six month 2015 amounts also include (i) decreases in earnings of $49 million and $128 million, respectively, related to losses on impairments and disposals of long-lived assets and equity investments; (ii) increase in earnings of $10 million for both periods related to a gain on the sale of SNG's Carthage Line; and (iii) increases in earnings of $4 million and $3 million, respectively, from other certain items.

Other

(c) Includes pipeline volumes for Kinder Morgan North Texas Pipeline LLC, Monterrey, TransColorado Gas Transmission Company LLC (TransColorado), Midcontinent Express Pipeline LLC, KMLP, Fayetteville Express Pipeline LLC, TGP, EPNG, South Texas Midstream, the Texas Intrastate Natural Gas Pipeline operations, CIG, Wyoming Interstate Company, L.L.C., CPG, SNG, Elba Express, Sierrita Gas Pipeline LLC, Natural Gas Pipeline Company of America LLC, Citrus and Ruby Pipeline, L.L.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.

(d) Represents volumes for the Texas Intrastate Natural Gas Pipeline operations and Kinder Morgan North Texas Pipeline LLC.

(e) Includes Oklahoma Midstream, South Texas Midstream, Eagle Ford Gathering LLC, North Texas Midstream, Camino Real Gathering Company, L.L.C. (Camino Real), Kinder Morgan Altamont LLC, KinderHawk Field Services LLC (KinderHawk), Endeavor, Bighorn Gas Gathering L.L.C., Webb Duval Gatherers, Fort Union Gas Gathering L.L.C., EagleHawk Field Services LLC (EagleHawk), Red Cedar Gathering Company and Hiland Midstream throughput volumes. Joint venture throughput is reported at our ownership share. Volumes for acquired pipelines are included at our ownership share for the entire period.

(f) Includes Hiland Midstream, EagleHawk and Camino Real. Joint Venture throughput is reported at our ownership share. Volumes for acquired pipelines are included at our ownership share for the entire period.

Below are the changes in both Segment EBDA before certain items and revenues before certain items, in the comparable three and six month periods ended June 30, 2016 and 2015:

Three months ended June 30, 2016 versus Three months ended June 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
South Texas Midstream	$(18)	(21)%	$(58)	(18)%
KinderHawk	(13)	(36)%	(14)	(35)%
KMLP	(7)	(140)%	(8)	(100)%
CIG	(7)	(10)%	(8)	(9)%
CPG	(4)	(31)%	(5)	(28)%
TransColorado	(4)	(50)%	(4)	(40)%
TGP	30	13%	49	17%
Hiland Midstream	17	47%	(8)	(5)%
Texas Intrastate Natural Gas Pipeline Operations	5	8%	(161)	(23)%
All others (including eliminations)	(6)	(1)%	(11)	(2)%
Total Natural Gas Pipelines	$(7)	(1)%	$(228)	(11)%

Six months ended June 30, 2016 versus Six months ended June 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
South Texas Midstream	$(29)	(17)%	$(130)	(21)%
KinderHawk	(29)	(38)%	(30)	(35)%
KMLP	(15)	(136)%	(17)	(100)%
CIG	(10)	(6)%	(11)	(6)%
CPG	(12)	(39)%	(13)	(32)%
TransColorado	(8)	(50)%	(8)	(42)%
TGP	106	22%	137	23%
Hiland Midstream	40	69%	34	16%
Texas Intrastate Natural Gas Pipeline Operations	(1)	(1)%	(368)	(24)%
All others (including eliminations)	(6)	(1)%	(17)	(2)%
Total Natural Gas Pipelines	$36	2%	$(423)	(10)%

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 and six month periods ended June 30, 2016 and 2015:

- decreases of $18 million (21%) and $29 million (17%), respectively, from South Texas Midstream primarily due to lower volumes and commodity prices, which resulted in decreases in revenue of approximately $58 million and $130 million, respectively, partially offset by decreases in costs of sales;
-

- decreases of $13 million (36%) and $29 million (38%), respectively, from KinderHawk due to the expiration of a minimum volume contract in 2015 and lower volumes;
- decreases of $7 million (140%) and $15 million (136%), respectively, from KMLP as a result of a customer contract buyout in the fourth quarter of 2015;

- decreases of $7 million (10%) and $10 million (6%), respectively, from CIG primarily due to elimination of revenue surcharge mechanism in 2016 as a result of latest rate case settlement and lower firm reservation revenues due to contract expirations and contract renewals at lower rates;
- decreases of $4 million (31%) and $12 million (39%), respectively, from CPG due primarily to lower transport revenues as a result of contract expirations;
- decreases of $4 million (50%) and $8 million (50%), respectively, from TransColorado primarily due to lower transport revenues as a result of contract expirations;
- increases of $30 million (13%) and $106 million (22%), respectively, from TGP primarily due to expansion projects placed in service during 2015 and favorable 2016 firm transport revenues;
- increases of $17 million (47%) and $40 million (69%), respectively, from Hiland Midstream primarily due to higher transportation and gathering volumes and favorable margins on renegotiated contracts, along with results of a full six months from our February 2015 Hiland acquisition; and
- increase of $5 million (8%) and a decrease of $1 million (1%), respectively, 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). The quarter-to-date increase was largely due to higher storage margins partially offset by lower transportation margins as a result of lower volumes. The decrease in revenues of $161 million and $368 million, respectively, resulted primarily from decreases in sales revenues due to lower commodity prices which was largely offset by a corresponding decreases in costs of sales.

CO2

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In millions, except operating statistics)			
Revenues(a)	$304	$353	$606	$799
Operating expenses	(102)	(110)	(200)	(224)
Gain (loss) on impairments and disposals of long-lived assets, net(b)	1	(9)	(20)	(9)
Other expense	(1)	—	—	—
Earnings from equity investments(b)	2	6	5	12
Income tax expense	(1)	—	(2)	(2)
Segment EBDA(b)	203	240	389	576
Certain items(b)	24	46	61	(9)
Segment EBDA before certain items	$227	$286	$450	$567
Change from prior period	Increase/(Decrease)			
Revenues before certain items	$(68)	(17)%	$(147)	(19)%
Segment EBDA before certain items	$(59)	(21)%	$(117)	(21)%
Southwest Colorado CO_2 production (gross)(Bcf/d)(c)	1.2	1.2	1.2	1.2
Southwest Colorado CO_2 production (net)(Bcf/d)(c)	0.6	0.6	0.6	0.6
SACROC oil production (gross)(MBbl/d)(d)	29.7	35.1	30.1	35.4
SACROC oil production (net)(MBbl/d)(e)	24.8	29.3	25.1	29.5
Yates oil production (gross)(MBbl/d)(d)	18.7	19.1	18.9	19.0
Yates oil production (net)(MBbl/d)(e)	8.3	8.6	8.4	8.5
Katz, Goldsmith, and Tall Cotton oil production (gross)(MBbl/d)(d)	6.8	5.6	6.8	5.4
Katz, Goldsmith and Tall Cotton oil production (net)(MBbl/d)(e)	5.7	4.7	5.8	4.6
NGL sales volumes (net)(MBbl/d)(e)	10.3	10.5	10.1	10.2
Realized weighted-average oil price per Bbl(f)	$62.17	$72.82	$60.85	$72.72
Realized weighted-average NGL price per Bbl(g)	$17.73	$20.04	$15.57	$20.36

____

48

Certain items affecting Segment EBDA

(a) Three and six month 2016 amounts include unrealized losses of $18 million and $28 million, respectively, and three and six month 2015 amounts include unrealized losses of $37 million and unrealized gains of $8 million, respectively, related to derivative contracts used to hedge forecasted crude oil sales. Six month 2015 amount also includes a favorable adjustment of $10 million related to carried working interest at McElmo Dome.

(b) In addition to the revenue certain items described in footnote (a) above: three and six month 2016 amounts also include decreases of $6 million and $12 million, respectively, in equity earnings for our share of a project write-off recorded by an equity investee, and six month 2016 amount also includes a $21 million increase in expense related to source and transportation project write-offs, and three and six month 2015 amounts also include decreases in earnings of $9 million for both periods related to an impairment charge associated with the pending sale of excess construction pipe.

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, a 100% interest in the Tall Cotton field and a 99% working interest in the Goldsmith Landreth unit.

(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 and six month periods ended June 30, 2016 and 2015.

Three months ended June 30, 2016 versus Three months ended June 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Source and Transportation Activities	$(5)	(6)%	$ (8)	(9)%
Oil and Gas Producing Activities	(54)	(26)%	(65)	(21)%
Intrasegment eliminations	—	— %	5	42 %
Total CO2	$(59)	(21)%	$ (68)	(17)%

Six months ended June 30, 2016 versus Six months ended June 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Source and Transportation Activities	$(14)	(9)%	$ (19)	(10)%
Oil and Gas Producing Activities	(103)	(25)%	(136)	(22)%
Intrasegment eliminations	—	— %	8	32 %
Total CO2	$(117)	(21)%	$ (147)	(19)%

The changes in Segment EBDA for our CO_2 business segment are further explained by the significant factors driving Segment EBDA before certain items in the comparable three and six month periods ended June 30, 2016 and 2015, which factors include lower revenues of $48 million and $117 million, respectively, from lower commodity prices and $25 million and $37 million, respectively, of decreased volumes, partially offset by $10 million and $30 million, respectively, in reduced operating costs, and severance and ad valorem tax expenses.

Terminals

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In millions, except operating statistics)			
Revenues(a)	$488	$470	$953	$927
Operating expenses	(195)	(189)	(386)	(378)
Gain (Loss) on impairments and disposals of long-lived assets, net(b)	3	—	(17)	—
Other expense	—	(2)	—	(2)
Earnings from equity investments	5	4	11	9
Interest income and Other, net	1	5	1	6
Income tax expense	(10)	(9)	(17)	(13)
Segment EBDA(b)	292	279	545	549
Certain items(b)	(9)	(8)	7	(14)
Segment EBDA before certain items	$283	$271	$552	$535
Change from prior period	Increase/(Decrease)			
Revenues before certain items	$14	3 %	$23	3 %
Segment EBDA before certain items	$12	4 %	$17	3 %
Bulk transload tonnage (MMtons)(c)	15.5	15.9	29.2	32.1
Ethanol (MMBbl)	16.3	16.3	31.6	32.3
Liquids leasable capacity (MMBbl)	88.3	81.5	88.3	81.5
Liquids utilization %(d)	94.8 %	93.2 %	94.8 %	93.2 %

Certain items affecting Segment EBDA

(a) Three and six month 2016 amounts include increases in revenue of $11 million and $16 million, respectively, and three and six month 2015 amounts include increases in revenue of $7 million and $13 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: three and six month 2016 amounts also include increases in expense of $2 million and $3 million, respectively, related to other certain items, and six month 2016 amount also includes $20 million related to losses on impairments and disposals of long-lived assets, and three and six month 2015 amounts also include increases in earnings of $1 million for each period 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.

Below are the changes in both Segment EBDA before certain items and revenues before certain items, in the comparable three and six month periods ended June 30, 2016 and 2015.

Three months ended June 30, 2016 versus Three months ended June 30, 2015

	Segment EBDA before certain items increase/(decrease)	Revenues before certain items increase/(decrease)

	(In millions, except percentages)			
Marine Operations	$13	54 %	$ 17	46 %
Gulf Liquids	11	19 %	9	11 %
Northeast	5	22 %	6	15 %
Alberta, Canada	1	4 %	5	15 %
Gulf Bulk	(9)	(38)%	(12)	(29)%
Lower River	(7)	(32)%	(8)	(22)%
Gulf Central	(7)	(30)%	(7)	(25)%
All others (including intrasegment eliminations and unallocated income tax expenses)	5	7 %	4	2 %
Total Terminals	$12	4 %	$ 14	3 %

50

Six months ended June 30, 2016 versus Six months ended June 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Marine Operations	$22	47 %	$ 31	42 %
Gulf Liquids	14	12 %	15	9 %
Northeast	7	15 %	9	11 %
Alberta, Canada	7	15 %	19	33 %
Gulf Bulk	(23)	(43)%	(25)	(29)%
Lower River	(11)	(27)%	(10)	(15)%
Gulf Central	(7)	(18)%	(6)	(13)%
All others (including intrasegment eliminations and unallocated income tax expenses)	8	6 %	(10)	(3)%
Total Terminals	$17	3 %	$ 23	3 %

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 and six month periods ended June 30, 2016 and 2015:

- increases of $13 million (54%) and $22 million (47%), respectively, from our Marine Operations related to the incremental earnings from the December 2015 and May 2016 deliveries of the Jones Act tankers, the “Lone Star State” and “Magnolia State,” respectively, and increased charter rates on the “Empire State” and “Evergreen State” Jones Act tankers;
- increases of $11 million (19%) and $14 million (12%), respectively, from our Gulf Liquids terminals, primarily related to higher volumes as a result of various expansion projects, including marine infrastructure improvements at our Galena Park, Pasadena, and North Docks terminal, as well as higher rates and ancillary service activities on existing business;
- increases of $5 million (22%) and $7 million (15%), respectively, from our Northeast terminals, primarily due to contributions from two terminals acquired as part of the BP Products North America Inc. acquisition which was completed in February 2016;
- increases of $1 million (4%) and $7 million (15%), respectively, from our Alberta, Canada terminals, primarily related to a new joint venture rail terminal placed into service in April 2015;
- decreases of $9 million (38%) and $23 million (43%), respectively, from our Gulf Bulk terminals, driven by decreased revenues and earnings of $11 million and $25 million, respectively, due to certain coal customer bankruptcies;
- decreases of $7 million (32%) and $11 million (27%), respectively, from our Lower River terminals, driven by decreased revenues and earnings of $7 million and $14 million, respectively, due to certain coal customer bankruptcies;
- decreases of $7 million (30%) and $7 million (18%), respectively, from our Gulf Central terminals, primarily as a result of a customer contract buyout in second quarter of 2015; and
- decreases of $1 million and $7 million, respectively, due to certain coal customer bankruptcies which impacted our Mid Atlantic terminals included in “All others”.

Products Pipelines

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In millions, except operating statistics)			
Revenues(a)	$401	$478	$797	$922
Operating expenses(b)	(141)	(210)	(294)	(419)
Gain (Loss) on impairments and disposals of long-lived assets, net(c)	5	—	(73)	(1)
Earnings from equity investments	15	12	28	22
Interest income and Other, net(d)	12	—	12	3
Income tax benefit (expense)	1	(3)	2	(4)
Segment EBDA(a)(b)(c)(d)	293	277	472	523
Certain items(a)(b)(c)(d)	3	(2)	111	(3)
Segment EBDA before certain items	$296	$275	$583	$520
Change from prior period	Increase/(Decrease)			
Revenues before certain items	$(79)	(17)%	$(126)	(14)%
Segment EBDA before certain items	$21	8 %	$63	12 %
Gasoline (MMBbl)(e)	97.6	97.9	188.9	186.4
Diesel fuel (MMBbl)	32.7	33.1	63.0	63.9
Jet fuel (MMBbl)	26.0	26.6	51.1	51.0
Total refined product volumes (MMBbl)(f)	156.3	157.6	303.0	301.3
NGL (MMBbl)(g)	9.7	9.7	19.0	19.4
Crude and condensate (MMBbl)(h)	27.9	25.2	58.8	43.7
Total delivery volumes (MMBbl)	193.9	192.5	380.8	364.4
Ethanol (MMBbl)(i)	10.7	10.5	20.8	20.4

____

Certain items affecting Segment EBDA

(a) Three and six month 2015 amounts include decreases in revenue of $2 million and $1 million, respectively, related to an unrealized swap loss.

(b) Three and six month 2016 amounts include increases in expense of $20 million for both periods related to a legal settlement. Six month 2016 amount also includes $31 million of rate case liability estimate adjustments associated with pre-2016 revenues. In addition to the revenue certain items described in footnote (a) above: three and six month 2015 amounts also include decreases in expense of $4 million for both periods related to a certain Pacific operations litigation matter.

(c) Three and six month 2016 amounts include a decrease in expense of a $5 million and a increase in expense of a $8 million, respectively, of non-cash impairment charges related to the potential sale of a Transmix facility; and six month 2016 amount also includes an increase in expense of $64 million related to the Palmetto project write-off.

(d) Three and six month 2016 amounts include $12 million of gains for both periods related to the sale of an equity investment.

Other

(e) Volumes include ethanol pipeline volumes.

(f) Includes Pacific, Plantation Pipe Line Company, Calnev, Central Florida and Parkway pipeline volumes. Joint venture throughput is reported at our ownership share.

(g) Includes Cochin and Cypress pipeline volumes. Joint venture throughput is reported at our ownership share.

(h) Includes Kinder Morgan Crude & Condensate, Double Eagle Pipeline LLC and Double H pipeline volumes. Joint venture throughput is reported at our ownership share.

(i) 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 and six month periods ended June 30, 2016 and 2015.

Three months ended June 30, 2016 versus Three months ended June 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Crude & Condensate Pipeline	$8	19 %	$ 6	13 %
KMCC - Splitter	6	67 %	8	89 %
Cochin	6	24 %	4	11 %
Double H pipeline	—	— %	1	6 %
Transmix	(1)	(10)%	(101)	(66)%
All others (including eliminations)	2	1 %	3	1 %
Total Products Pipelines	$21	8 %	$ (79)	(17)%

Six months ended June 30, 2016 versus Six months ended June 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Crude & Condensate Pipeline	$27	34 %	$ 28	33 %
KMCC - Splitter	18	180%	25	250 %
Cochin	1	2 %	3	4 %
Double H pipeline	8	44 %	12	52 %
Transmix	—	— %	(202)	(67)%
All others (including eliminations)	9	3 %	8	2 %
Total Products Pipelines	$63	12 %	$ (126)	(14)%

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 and six month periods ended June 30, 2016 and 2015:

- increases of $8 million (19%) and $27 million (34%), respectively, from our Kinder Morgan Crude & Condensate Pipeline driven primarily by an increase in pipeline throughput volumes from existing customers and additional volumes from new customers associated with expansion projects;
- increases of $6 million (67%) and $18 million (180%), respectively, from our KMCC - Splitter due to first and second phases in full operation for 2016. Start up of first phase was in March 2015 and second phase was in July 2015;
- increases of $6 million (24%) and $1 million (2%), respectively, from Cochin due to third party operational constraints downstream of the pipeline which occurred during the second quarter of 2015;
- flat and $8 million (44%), respectively, due to a full six months of results from our Double H pipeline, which began operations in March 2015; and
- decrease of $1 million (10%) and flat, respectively, from our Transmix processing operations. The decreases in revenues of $101 million and $202 million, respectively, and associated decreases in costs of goods sold were driven

by lower sales volumes.

Kinder Morgan Canada

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In millions, except operating statistics)			
Revenues	$63	$65	$122	$125
Operating expenses	(21)	(23)	(39)	(42)
Interest income and Other, net	4	2	9	5
Income tax expense	(6)	(7)	(12)	(10)
Segment EBDA	$40	$37	$80	$78
Change from prior period	Increase/(Decrease)			
Revenues	$(2)	(3)%	$(3)	(2)%
Segment EBDA	$3	8%	$2	3%
Transport volumes (MMBbl)(a)	28.7	29.7	57.3	57.3

____

(a) Represents Trans Mountain pipeline system volumes.

For the comparable three and six month periods of 2016 and 2015, the Kinder Morgan Canada business segment had increases in Segment EBDA of $3 million (8%) and $2 million (3%) primarily due to increased Washington State volumes partially offset by an unfavorable impact from foreign exchange rates.

Other

This segment contributed losses of $5 million and $13 million for the three and six months ended June 30, 2016, respectively, and contributed losses of $40 million and $46 million for the three and six months ended June 30, 2015, respectively. However, three and six months ended June 30, 2016 losses included certain items which increased Segment EBDA by $3 million and $4 million, respectively; and both three and six month 2015 losses included certain items of $33 million which decreased Segment EBDA and were primarily related to a certain litigation matter. After taking into effect the certain items, the losses for the three and six months ended June 30, 2016 increased by $1 million and $4 million, respectively, when compared with the same prior year period.

General and Administrative, Interest, and Noncontrolling Interests

	Three Months Ended June 30,			
	2016	2015	Increase/(decrease)	
	(In millions, except percentages)			
General and administrative expense(a)(d)	$189	$164	$25	15%
Certain items(a)	(22)	9	(31)	(344)%
Management fee reimbursement(d)	(9)	(9)	—	—%
General and administrative expense before certain items	$158	$164	$(6)	(4)%
Unallocable interest expense net of interest income and other, net(b)	$470	$472	$(2)	—%
Certain items(b)	40	55	(15)	(27)%

Unallocable interest expense net of interest income and other, net, before certain items	$510	$527	$ (17)	(3)%
Net income attributable to noncontrolling interests	$3	$9	$ (6)	(67)%
Noncontrolling interests associated with certain items(c)	3	(1)	4	400 %
Net income attributable to noncontrolling interests before certain items	$6	$8	$ (2)	(25)%

	Six Months Ended June 30,			
	2016	2015	Increase/(decrease)	
	(In millions, except percentages)			
General and administrative expense(a)(d)	$379	$380	$ (1)	— %
Certain items(a)	(28)	(29)	1	3 %
Management fee reimbursement(d)	(17)	(18)	1	6 %
General and administrative expense before certain items	$334	$333	$ 1	— %
Unallocable interest expense net of interest income and other, net(b)	$912	$986	$ (74)	(8)%
Certain items(b)	109	55	54	98 %
Unallocable interest expense net of interest income and other, net, before certain items	$1,021	$1,041	$ (20)	(2)%
Net income (loss) attributable to noncontrolling interests	$2	$(1)	$ 3	300 %
Noncontrolling interests associated with certain items(c)	9	14	(5)	(36)%
Net income attributable to noncontrolling interests before certain items	$11	$13	$ (2)	(15)%

Certain items

(a) Three and six month 2016 amounts include (i) increases in expense of $4 million and $8 million, respectively, related to certain corporate legal matters; (ii) increase in expense of $12 million for both periods related to severance costs; and (iii) increases in expense of $5 million and $8 million, respectively, related to acquisition costs. Three month 2016 amount also includes an increase in expense of $1 million related to pension credit income. Three and six month 2015 amounts include increases in expense of (i) $1 million and $40 million, respectively, related to certain corporate legal matters; and (ii) $1 million and $12 million, respectively, related to costs associated with our Hiland acquisition. Partially offsetting these three and six month 2015 increases are decreases in expense of $11 million and $23 million, respectively, related to pension credit income.

(b) Three and six month 2016 amounts include decreases in interest expense of (i) $18 million and $37 million, respectively, related to debt fair value adjustments associated with acquisitions; and (ii) $22 million and $72 million, respectively, related to non-cash true-ups of our estimates of swap ineffectiveness. Three and six month 2015 amounts include decreases in interest expense of (i) $23 million and $30 million, respectively, related to non-cash true-ups of our estimates of swap ineffectiveness; (ii) $19 million and $35 million, respectively, related to debt fair value adjustments associated with acquisitions; and (iii) $13 million for both periods associated with a certain Pacific operations litigation matter. Six month 2015 amount also includes a $23 million increase in interest expense for a non-cash adjustment related to a litigation matter.

(c) Three and six month 2016 amounts include losses of $3 million and $9 million, respectively, and three and six month 2015 amounts include a gain of $1 million and a loss of $14 million, respectively, associated with Natural Gas Pipelines segment certain items and disclosed above in "—Natural Gas Pipelines."

Other

(d) Three and six month 2016 and 2015 amounts include general and administrative management fee revenues from an equity investee of $9 million, $9 million, $17 million and $18 million, respectively. These amounts were recorded to the "Product sales and other" caption with the offsetting expenses primarily included in the "General and administrative" expense caption in our accompanying consolidated statements of income.

General and administrative expenses before certain items for the three and six months ended June 30, 2016, as compared to the respective prior periods decreased $6 million and increased $1 million, respectively. The quarter-to-date decrease from 2015 was primarily driven by lower legal costs, outside services and labor expenses partially offset by lower capitalized costs due to reduced capital expenditures. The year-to-date increase from 2015 was primarily driven by lower capitalized costs partially offset by lower outside services and labor expenses.

In the table above, we report our interest expense as “net,” meaning that we have subtracted unallocated interest income and capitalized interest from our total interest expense to arrive at one interest amount. Our consolidated interest expense net of interest income and other, net before certain items for the three and six months ended June 30, 2016, as compared to the respective prior periods decreased $17 million and $20 million, respectively. The decreases in interest expense were due to lower weighted average debt balances, 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 June 30, 2016 and December 31, 2015, approximately 28% and 27%, respectively, of our debt balances (excluding debt fair value adjustments) were subject to variable interest rates—either as short-term or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swaps. For more information on our interest rate swaps, see Note 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. The decreases in net income attributable to noncontrolling interests before certain items for the three and six months ended June 30, 2016 as compared to the respective prior periods was $2 million for both periods.

Income Taxes

Our tax expense for the three months ended June 30, 2016 was approximately $213 million as compared to $189 million for the same period of 2015. The $24 million increase in tax expense was primarily due to higher pre-tax earnings.

Our tax expense for the six months ended June 30, 2016 was approximately $367 million as compared to $413 million for the same period of 2015. The $46 million decrease in tax expense was primarily due to lower 2016 year-to-date earnings as a result of asset impairments and project write-offs, and adjustments to our income tax reserve for uncertain tax positions.

Liquidity and Capital Resources

General

As of June 30, 2016, we had $180 million of “Cash and cash equivalents” on our consolidated balance sheet, a decrease of $49 million (21%) from December 31, 2015. 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 strong cash flow from operations, providing a source of funds of $2,344 million and $2,538 million in the first six months of 2016 and 2015, 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, and during 2016, to fund our expansion capital expenditures.

On July 10, 2016, we announced the anticipated sale of a 50% interest in our SNG natural gas pipeline system to Southern Company for an expected $1.47 billion and the formation of a joint venture, which will include our remaining 50% interest in SNG, which we will operate. Inclusive of existing SNG debt, the transaction equates to an SNG total enterprise value of $4.15 billion. We intend to use all of the proceeds from this transaction to reduce debt. As of June 30, 2016, SNG had $1,211 million of debt outstanding (including a current portion of $500 million) which we do not expect to consolidate subsequent to the close of the transaction. Subject to customary closing conditions and regulatory approvals, the transaction is expected to close in the third or early fourth quarter of 2016, at which time, any difference between the sales price and the proportionate carrying value of the interests in SNG being sold would be recognized.

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

In general, we expect that our short-term liquidity needs will be met primarily through retained cash from operations or short-term borrowings. We also expect that our current common equity dividend level will allow us to use retained cash to fund our growth projects in 2016. Moreover, by continuing to focus on high-grading our growth project backlog to allocate capital to the highest return opportunities, we do not expect to need to access the capital markets to fund our growth projects for the foreseeable future beyond 2016.

Short-term Liquidity

As of June 30, 2016, our principal sources of short-term liquidity are (i) our $5.0 billion revolving credit facility and associated $4.0 billion commercial paper program and (ii) cash from operations. The loan commitments under our revolving credit facility can be used for working capital and other general corporate purposes and as a backup to our commercial paper program. Borrowings under our commercial paper program and letters of credit reduce borrowings allowed under our credit facility. We provide for liquidity by maintaining a sizable amount of excess borrowing capacity under our credit facility and, as previously discussed, have consistently generated strong cash flows from operations.

Our short-term debt as of June 30, 2016 was $3,419 million, primarily consisting of (i) $700 million outstanding borrowings under our $5.0 billion revolving credit facility; (ii) $24 million outstanding borrowings under our $4.0 billion commercial paper program; and (iii) $2,541 million of senior notes that mature in the next year. We intend to refinance our short-term debt through additional 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 combined balance of short-term debt as of December 31, 2015 was $821 million.

We had working capital (defined as current assets less current liabilities) deficits of $4,096 million and $1,241 million as of June 30, 2016 and December 31, 2015, respectively. Our current liabilities 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 $2,855 million (230%) unfavorable change from year-end 2015 was primarily due to a net increase in our credit facility and commercial paper borrowings and an increase in our current portion of long term debt, offset partially by a favorable change in payables. 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 cash available to pay dividends 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 six months ended June 30, 2016, and the amount we expect to spend for the remainder of 2016 to sustain and grow our businesses are as follows:

	Six Months Ended June 30, 2016	2016 Remaining	Total
	(In millions)		
Sustaining capital expenditures(a)	$245	$ 318	$563
Discretionary capital expenditures(b)(c)	$1,581	$ 1,218	$2,799

____

(a) Six-months 2016, 2016 Remaining, and Total 2016 amounts include $42 million, $54 million, and $96 million, respectively, for our proportionate share of sustaining capital expenditures of unconsolidated joint ventures.

(b) Six-months 2016 amount includes an increase of $566 million of discretionary capital expenditures of unconsolidated joint ventures (including a NGPL Holdings LLC contribution) and acquisitions (primarily BP terminals acquisition) and divestitures and a decrease of a combined $252 million of net changes from accrued capital expenditures and contractor retainage.

(c) 2016 Remaining amount includes our contributions to certain unconsolidated joint ventures and small acquisitions and divestitures, net of contributions estimated from unaffiliated joint venture members for consolidated 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, 2015 in our 2015 Form 10-K.

Commitments for the purchase of property, plant and equipment as of June 30, 2016 and December 31, 2015 were $1,773 million and $1,229 million, respectively. The $544 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 $194 million in cash provided by operating activities for the first six months of 2016 compared to the respective 2015 period was primarily attributable to:

- a $213 million decrease associated with net changes in working capital items and non-current assets and liabilities. The decrease was driven, among other things, primarily by a non-recurring $195 million income tax refund and a $73 million payment under a take-or-pay contract that we received in 2015; and
- a $19 million increase in cash from overall net income after adjusting our period-to-period $72 million decrease in net income for non-cash items primarily consisting of the following: (i) net losses on impairments and disposals of long-lived assets (see discussion above in "—Results of Operations"); (ii) changes in DD&A expenses (including amortization of excess cost of equity investments) and deferred income taxes; and (iii) change in earnings from equity investments.

Investing Activities

The $1,864 million net decrease in cash used in investing activities for the first six months of 2016 compared to the respective 2015 period was primarily attributable to:

- a $1,586 million decrease in expenditures for acquisitions and investments in 2016 compared to the respective 2015 period. The overall decrease in acquisitions was primarily related to the $324 million portion of the purchase price we paid in 2016 for the BP terminals acquisition, versus $1,706 million (net of cash assumed) and $158 million we paid for the Hiland and Vopak acquisitions, respectively, in the 2015 period;
- a $439 million reduction in capital expenditures resulting from the high-grading of our project backlog to focus on allocating capital to the highest return opportunities; and
- a $216 million increase from proceeds of sales of property, plant and equipment, certain assets and investments; partially offset by,
- a $318 million increase in contributions to equity investments in 2016 compared to the respective 2015 period, primarily due to a $312 million contribution to our 50% investment in NGPL Holdings LLC in 2016.

Financing Activities

The net decrease of $1,576 million in cash provided by financing activities for the first six months of 2016 compared to the respective 2015 period was primarily attributable to:

- a $2,562 million decrease in cash resulting from the issuances of our Class P shares under our equity distribution agreement in 2015 and no activity in 2016;
- a $483 million net decrease in net debt proceeds. See Note 3 “Debt” for further information regarding our debt activity;
- a $76 million decrease in cash due to dividends paid to our mandatory convertible preferred shareholders in 2016;
- a $1,447 million in reduced dividend payments paid to our common shareholders; and
- an $87 million increase in contributions provided by noncontrolling interests, primarily reflecting the contributions received from BP for its 25% share of a newly formed joint venture. See Note 2 “Acquisitions and Divestitures” for further information regarding this joint venture.

Common Dividends

We expect to declare common dividends of $0.50 per share on our common stock for 2016 ($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, 2015	$ 0.125	January 20, 2016	February 1, 2016	February 16, 2016
March 31, 2016	$ 0.125	April 20, 2016	May 2, 2016	May 16, 2016
June 30, 2016	$ 0.125	July 20, 2016	August 1, 2016	August 15, 2016

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 2015 Form 10-K. All of these matters will be taken into consideration by our board of directors in declaring dividends.

Our common 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 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	Date of declaration	Date of record	Date of dividend

period				
October 30, 2015 through January 25, 2016	$23.291667	November 17, 2015	January 11, 2016	January 26, 2016
January 26, 2016 through April 25, 2016	$24.375000	January 20, 2016	April 11, 2016	April 26, 2016
April 26, 2016 through July 25, 2016	$24.375000	April 20, 2016	July 11, 2016	July 26, 2016

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, 2015, in Item 7A in our 2015 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 June 30, 2016, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. There has been no change in our internal control over financial reporting during the quarter ended June 30, 2016 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 2015 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.

On July 19, 2016, the Compensation Committee of our Board of Directors approved a revised form of restricted stock unit agreement under the KMI 2015 Amended and Restated Stock Incentive Plan. The form agreement was revised to provide clarifying language regarding the applicability of Internal Revenue Code Section 162(m) to an employee.

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 26, 2016 (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 June 30, 2016.
10.2		2016 Form of Employee Restricted Stock Unit Agreement.
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 and six months ended June 30, 2016 and 2015; (ii) our Consolidated Statements of Comprehensive Income for the three and six months ended June 30, 2016 and 2015; (iii) our Consolidated Balance Sheets as of June 30, 2016 and December 31, 2015; (iv) our Consolidated Statements of Cash Flows for the six months ended June 30, 2016 and 2015; (v) our Consolidated Statements of Stockholders' Equity for the six months ended June 30, 2016 and 2015; 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:	July 22, 2016	By:	/s/ Kimberly A. Dang
			Kimberly A. Dang
			Vice President and Chief Financial Officer
			(principal financial and accounting officer)

62