KINDER MORGAN, INC.
Form 10-K
February 23, 2015
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2014
or

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

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

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

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

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

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

Title of each class	Name of each exchange on which registered
Class P Common Stock	New York Stock Exchange
Warrants to Purchase Class P Common Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes þ No o

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).
Large accelerated filer þ Accelerated filer o Non-accelerated filer o Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes o No þ

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on closing prices in the daily composite list for transactions on the New York Stock Exchange on June 30, 2014 was approximately $24,279,037,627. As of February 2, 2015, the registrant had 2,130,052,022 Class P shares outstanding.

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KINDER MORGAN, INC. AND SUBSIDIARIES
GLOSSARY

Company Abbreviations

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

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

Common Industry and Other Terms

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

		amortization expenses, including amortization of excess cost of equity investments	PHMSA	=	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
EPA	=	United States Environmental Protection Agency			
FASB	=	Financial Accounting Standards Board			
FERC	=	Federal Energy Regulatory Commission	SEC	=	United States Securities and Exchange Commission
FTC	=	Federal Trade Commission			
GAAP	=	United States Generally Accepted Accounting Principles	TBtu	=	trillion British Thermal Units
			WTI	=	West Texas Intermediate

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

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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 service debt 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. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

- the timing and extent of changes in price trends and overall demand for NGL, refined petroleum products, oil, CO_2, natural gas, electricity, coal, steel and other bulk materials and chemicals and certain agricultural products in North America;

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

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

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

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

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

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

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

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

- changes in laws or regulations, third-party relations and approvals, and decisions of courts, regulators and governmental bodies that may adversely affect our business or our ability to compete;

- interruptions of electric power supply to our facilities due to natural disasters, power shortages, strikes, riots, terrorism (including cyber attacks), war or other causes;

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

- the ability to complete expansion projects and construction of our vessels on time and on budget;
- the timing and success of our business development efforts, including our ability to renew long-term customer contracts;
- changes in accounting pronouncements that impact the measurement of our results of operations, the timing of when such measurements are to be made and recorded, and the disclosures surrounding these activities;
- changes in tax law;

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- our ability to offer and sell debt securities, or obtain debt financing in sufficient amounts and on acceptable terms to implement that portion of our business plan that contemplates growth through acquisitions of operating businesses and assets and expansions of our facilities;
- our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at a competitive disadvantage compared to our competitors that have less debt, or have other adverse consequences;
- our ability to obtain insurance coverage without significant levels of self-retention of risk;
- acts of nature, sabotage, terrorism (including cyber attacks) or other similar acts or accidents causing damage to our properties greater than our insurance coverage limits;
- possible changes in our and our subsidiaries credit ratings;
- capital and credit markets conditions, inflation and fluctuations in interest rates;
- the political and economic stability of the oil producing nations of the world;
- national, international, regional and local economic, competitive and regulatory conditions and developments;
- our ability to achieve cost savings and revenue growth;
- foreign exchange fluctuations;
- the extent of our success in developing and producing CO_2 and oil and gas reserves, including the risks inherent in development drilling, well completion and other development activities;
- engineering and mechanical or technological difficulties that we may experience with operational equipment, in well completions and workovers, and in drilling new wells; and
- unfavorable results of litigation and the outcome of contingencies referred to in Note 16 “Litigation, Environmental and Other” to our consolidated financial statements.

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

See Item 1A “Risk Factors” for a more detailed description of these and other factors that may affect the forward-looking statements. When considering forward-looking statements, one should keep in mind the risk factors described in Item 1A “Risk Factors.” The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation, other than as required by applicable law, and described below under Items 1 and 2, “Business and Properties——(a) General Development of Business—Recent Developments—2015 Outlook”, to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

PART I

Items 1 and 2. Business and Properties.

We are the largest energy infrastructure and the third largest energy company in North America with an enterprise value of more than $125 billion. We own an interest in or operate approximately 80,000 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. Our common stock trades on the NYSE under the symbol “KMI.”

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(a) General Development of Business

Organizational Structure

On November 26, 2014, we completed our acquisition, pursuant to three separate merger agreements, of all of the outstanding common units of Kinder Morgan Energy Partners, L.P. (NYSE: KMP) and El Paso Pipeline Partners, L.P. (NYSE: EPB) and all of the outstanding shares of Kinder Morgan Management, LLC (NYSE: KMR) that we did not already own. The transactions, valued at approximately $77 billion, are referred to collectively as the “Merger Transactions.”

Upon completion of the Merger Transactions: (i) each publicly held KMR share received 2.4849 shares of KMI common stock; (ii) through the election and proration mechanisms in the KMP merger agreement, on average, each common unit held by a public KMP unitholder received 2.1931 shares of KMI common stock and $10.77 in cash; and (iii) through the election and proration mechanisms in the EPB merger agreement, on average, each common unit held by a public EPB unitholder received 0.9451 shares of KMI common stock and $4.65 in cash. The cash payments to the public unitholders of KMP and EPB totaled approximately $3.9 billion.

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

Additionally, on January 1, 2015, EPB and its subsidiary, EPPOC merged with and into KMP and were dissolved. As a result of such merger, all of the subsidiaries of EPB and EPPOC are wholly owned subsidiaries of KMP.

Prior to November 26, 2014, we owned an approximate 10% limited partner interest (including our interest in KMR) and the 2% general partner interest including incentive distribution rights in KMP, and an approximate 39% limited partner interest and the 2% general partner interest and incentive distribution rights in EPB. Effective with the Merger Transactions, the incentive distribution rights held by the general partner of KMP was eliminated.

Historically, most of our operating assets were owned and most of our investments were conducted by KMP and EPB.

The equity interests in KMP, EPB and KMR (which are all consolidated in our financial statements) owned by the public prior to November 26, 2014 are reflected within “Noncontrolling interests” in our accompanying December 31, 2013 consolidated balance sheet. The earnings recorded by KMP, EPB and KMR that are attributed to their units and shares, respectively, held by the public prior to November 26, 2014 are reported as “Net income attributable to noncontrolling interests” in our accompanying consolidated statements of income.

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

Recent Developments

The following is a brief listing of significant developments and updates related to our major projects since December 31, 2013. Additional information regarding most of these items may be found elsewhere in this report. “Capital Scope” is estimated for our share of the entire project which may include portions not yet completed.

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Asset or project	Description	Activity	Capital Scope
Natural Gas Pipelines - Placed in service or acquisitions			
Hiland Partners	Assets consist of crude oil gathering and transportation pipelines and gas gathering and processing systems, primarily serving production from the Bakken Formation in North Dakota and Montana.	Acquired February 2015.	$3.0 billion
DK Expansion	Construction of the second of two 400,000 Mcf/d cryogenic unit expansions and compression to support volume growth in the Eagle Ford shale.	Plant placed in service third quarter 2014. Compression placed in service fourth quarter 2014.	$236 million
TGP Utica Backhaul	Expansion project that provides 500,000 Dth/d incremental natural gas transportation capacity, from Utica south to the Tennessee Zone 1 area.	Placed in service April 2014.	$175 million
KM Texas and Mier-Monterrey pipelines expansion	Expansion project provides 150,000 Dth/d of service to PEMEX Gas y Petroquímica Básica on an interim basis and is part of a larger project that is supported by three customers in Mexico that entered into long-term firm transportation contracts.	First portion placed in service September and December 2014, expected second phase in service 2016.	$105 million
Keystone Storage	Multi-cycle gas storage facility in West Texas near the WAHA Hub that connects to EPNG and two other interstate pipelines and has 8.5 Bcf of total storage capacity.	Acquired July 2014.	$92 million
TGP Rose Lake	Located in northeastern Pennsylvania, fully subscribed for 10-year terms by South Jersey Resources and Statoil and provides an additional 230,000 Dth/d per day of capacity.	Placed in service November 2014.	$74 million
Sierrita Gas Pipeline	The 60-mile pipeline provides 200 MMcf/d of capacity and extends from near Tucson to the U.S.-Mexico border near Sasabe, Arizona.	Placed in service October 2014.	$66 million
Natural Gas Pipelines - Other announcements			
TGP Northeast Energy Direct	Development of a 171-mile supply path that will extend from the Marcellus supply area in Pennsylvania to a point near Wright, New York, the market path will consist of 188 miles of mainline from Wright to Dracut, Massachusetts.	Expected in service November 2018.	$4.5 to $5.5 billion
Elba Liquefaction	Building of new natural gas liquefaction and export facilities at our SLNG natural gas terminal on Elba Island, near Savannah, Ga., with a total capacity of 2.5 million tonnes per year of LNG, equivalent to 350 MMcf/d of natural gas.	Planning and engineering activities continue, expected full in service 2018.	$1.3 billion
TGP Broad Run Flexibility and Broad Run Expansion	Modification to existing pipelines to create 790,000 Dth/d of north-to-south gas transportation capacity from a receipt point in West Virginia to delivery points in Mississippi and Louisiana.	Final facility design, expected in service November 2015 and November 2017.	$751 million
EPNG upstream Sierrita			$529 million

	Expansion projects to provide 550,000 Dth/d firm natural gas transport capacity, which involves a first phase of system improvements to deliver volumes to the Sierrita Pipeline, and the second phase that will result in incremental deliveries of natural gas to Arizona and California.	Phase one placed in service October 2014, phase two expected fully in service October 2020.	
Elba Express Company and SNG expansion	Expansion project that provides 854,000 Dth/d incremental natural gas transportation service supporting the needs of customers in Georgia, South Carolina and northern Florida, and also serving Elba Liquefaction.	Expected in service 2016 (first phase) and 2017.	$282 million
TGP South System Flexibility	Expansion project that provides more than 900 miles of north-to-south transportation capacity of 500,000 Dth/d on our TGP system from Tennessee to South Texas and expands our transportation service to Mexico.	Initial volume placed into service January 2015, with the remainder expected December 2016.	$187 million
Texas Intrastate SK Freeport LNG	Entered into a 20-year firm transportation services agreement with SK E&S LNG, LLC in December 2014. We will provide more than 320,000 Dth/d of firm natural gas transportation services.	Completion expected third quarter 2019.	$153 million
KMLP Magnolia LNG Liquefaction Transport	Upgrades to this existing pipeline system to provide 700,000 Dth/d capacity to serve Magnolia LNG in the Lake Charles, La., area.	Precedent agreement executed. Expected in service third quarter 2018.	$143 million

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Asset or project	Description	Activity	Capital Scope
Natural Gas Pipelines - Other announcements continued			
TGP Susquehanna West	Expansion project that provides 145,000 Dth/d incremental natural gas transportation capacity, serving the northeast Marcellus to points of liquidity.	Capacity awarded. Precedent agreement executed. Expected in service November 2017.	$143 million
TGP Cameron LNG	Compressor station modifications and new pipeline laterals for enhanced supply access to the Perryville Hub, for a capacity of 900,000 Dth/d.	Precedent agreements executed. Expected in service fourth quarter 2018.	$138 million
TGP Marcellus to Milford	An expansion project to provide additional firm capacity from the Marcellus supply basin to TGP's interconnection with Columbia Gas Transmission in Pike County, Pennsylvania. The capacity of this expansion will be at least 135,000 Dth/d.	Precedent agreements executed. Expected in service June 2018.	$129 million
TGP Lone Star	Two greenfield compressor stations to provide supply to the Corpus Christi LNG liquefaction project, for a capacity of 300,000 Dth/d.	Capacity awarded. Precedent agreement executed. Expected in service July 2019.	$123 million
TGP Connecticut Expansion	Expansion project that provides 72,100 Dth/d incremental natural gas transportation capacity, serving the New England market.	Precedent agreements executed. Expected in service November 2016.	$82 million
Texas Intrastate Cheniere Corpus Christi LNG	Project provides 250,000 Dth/d of firm natural gas transportation service, as well as 3 Bcf of natural gas storage capacity, to serve the LNG export facility. Entered into 15-year firm transportation and multi-year storage agreements with Cheniere Energy, through its subsidiary, Corpus Christi Liquefaction.	Agreements signed December 2014. Startup expected fourth quarter 2018.	$77 million
CO_2 - Placed in service			
Yellow Jacket Central Facility expansion	A booster compression project at the McElmo Dome source field in southwestern Colorado that will increase CO_2 production by up to 90 MMcf/d.	Placed in service September 2014.	$214 million
CO_2 - Other announcements			
St. Johns Development	Developing an additional 300 MMcf/d and building a new pipeline (Lobos) to transport CO_2 from our St. Johns source field in Apache County, Arizona.	Expected in service 2018.	$982 million
Cow Canyon development	An expansion project that will increase CO_2 production in the Cow Canyon area of the McElmo Dome source field by 200 MMcf/d.	Expected full in service fourth quarter 2015.	$344 million
Cortez Pipeline expansion - phase 1	Project will increase capacity from 1.35 Bcf/d to 1.7 Bcf/d on this existing pipeline. This pipeline will transport CO_2 from southwestern Colorado to eastern New Mexico and west Texas for use in enhanced oil recovery projects.	Expected full in service fourth quarter 2015.	$233 million
Terminals - Placed in service or acquisitions			

American Petroleum Tankers and State Class Tankers	Purchase of five on-the-water Jones Act tankers, each operating pursuant to long-term time charters with high quality counterparties, and assumption of a contract to receive four more tankers currently under construction, which will be operated pursuant to long-term time charters with a major integrated oil company.	Acquired January 2014.	$961 million
Edmonton Terminal expansion—Phases 1 and 2	A two-phase expansion project that adds 4.6 million barrels of storage capacity to our Edmonton terminal for crude oil and refined petroleum products, supported by long-term contracts with major producers and refiners.	Placed in service first quarter 2014 (phase 1) and fourth quarter 2014 (phase 2).	$402 million
BOSTCO expansion—Phases 1 and 2	A two-phase greenfield joint venture terminal development that adds 7.1 million barrels of distillate, residual fuel and other black oil product storage at the Houston Ship Channel site, fully subscribed and supported by long-term contracts with major oil companies.	Placed in service second quarter 2014 (phase 1) and third quarter 2014 (phase 2).	$305 million
Pennsylvania and Florida Jones Act Tankers	Purchase from Crowley Maritime of two Jones Act tankers, engaging in the marine transportation of crude oil, condensate, and refined products in the U.S, both supported by long-term time charters with major shippers.	Acquired November 2014.	$270 million

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Asset or project	Description	Activity	Capital Scope
Terminals - Placed in service or acquisitions continued			
Deepwater Coal Handling (Deer Park, TX)	Expansion project at our multi-purpose Deepwater Terminal along the Houston Ship Channel adds 10 million tons per year of coal export capacity secured by long-term take-or-pay volume commitments.	Construction completed third quarter of 2014.	$184 million
Lousiana Chemical Tankage Expansion	In two separate projects added additional chemical storage to our Harvey, LA terminal and storage and various marine, truck, and rail infrastructure improvements in support of Methanex Corporation's relocated production plant.	Construction completed second half of 2014.	$85 million
International Marine Terminal Phase 3	Phase 3 expansion at the joint venture International Marine Terminal in Louisiana adds additional export coal capacity supported by long-term take-or-pay volume commitments.	Construction completed first quarter of 2014.	$64 million
Terminals - Other announcements			
Edmonton Rail Terminal	Announced expansion increases capacity to over 210,000 bpd at the joint venture crude rail terminal in Edmonton. The facility, supported by long-term customer contracts, will be connected via pipeline to the Trans Mountain pipeline and be capable of sourcing all crude streams handled by Kinder Morgan for delivery by rail to North American markets and refineries.	Expected in service first quarter 2015.	$249 million
Pasadena and Galena Park Infrastructure Improvements and Greensport Ship Dock 2	Construction of 2.1 million barrels of storage between the Pasadena and Galena Park terminals, a new ship dock, and various other infrastructure improvements providing enhanced product export capabilities, supported by long-term customer contracts.	Phase into service in 2016 and 2017.	$238 million
Houston Export Terminal	Brownfield expansion along Houston Ship Channel will add 1.5 million barrels of liquids storage capacity and a new ship dock that will handle ocean going vessels, supported by a long-term contract with a major ship channel refiner.	Expected in service first quarter 2017.	$172 million
Royal Vopak U.S. Terminal acquisition	Announced purchase of three U.S. Terminals and one undeveloped site.	Expected acquisition close first quarter 2015.	$158 million
Galena Park Tank Project and Pasadena Barge Dock	Construction of nine storage tanks with total shell capacity of 1.2 million barrels and a new barge dock at Pasadena, supported by long-term customer contracts.	Final three tanks expected in service first quarter 2015; barge dock expected in service fourth quarter 2015.	$124 million
Products Pipelines - Placed in service			
Cochin Reversal project	Conversion of the line to northbound condensate service to serve oilsands producers' needs in western Canada, supported by long-term customer	In service July 2014.	$301 million

	contracts.		
KM Crude & Condensate Helena Extension	Constructed 30 miles of new pipeline from Helena to Dewitt, the Helena pump station, two new tanks and a four lane truck offload system, supported by long-term customer contracts.	In service September 2014.	$99 million
Products Pipelines - Other announcements			
Palmetto Pipeline	Construction of new pipeline, underpinned by long-term customer contracts, to move gasoline, diesel and ethanol from Louisiana, Mississippi and South Carolina to points in South Carolina, Georgia and Florida.	Close of successful binding open season November 2014, expected in service July 2017.	$778 million
Cochin Utopia East	Building of new 240 mile pipeline, supported by long-term customer contracts, to transport ethane and ethane-propane mixtures from the prolific Utica Shale, with an initial design capacity of 50,000 bpd, expandable to more than 75,000 bpd.	Work continues, expected in service January 2018.	$507 million
KM Condensate Processing Facility	Project includes building two separate units to split condensate into various components and construct storage tanks totaling almost 2 million barrels to support the processing operation, supported by long-term customer contracts.	Construction continues, expected in service March 2015 (phase 1) and July 2015 (phase 2).	$383 million
KM Crude and Condensate Pipeline/ Double Eagle Pipeline	Project will provide transportation of Eagle Ford crude and condensate to the Houston Ship Channel.	Continues to see strong interest, expected in service second quarter 2015.	$235 million

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Asset or project	Description	Activity	Capital Scope
Products Pipelines - Other announcements continued			
Utica Marcellus Texas Pipeline	Project involves the abandonment and conversion of over 1,000 miles of natural gas service on TGP, the construction of approximately 200 miles of new pipeline from Louisiana to Texas and 155 miles of new laterals in Pennsylvania, Ohio and West Virginia.	Pending customer commitments, expected in service 2018.	still developing
Kinder Morgan Canada			
Trans Mountain Expansion Project	An increase of capacity on our Trans Mountain pipeline system from approximately 300,000 to 890,000 barrels per day, underpinned by long-term take-or-pay contracts.	Currently engaged in final approval process with the NEB, expected in service third quarter 2018.	$5.4 billion

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Financings

- For information about our 2014 debt offerings and retirements, see Note 8 "Debt" to our consolidated financial statements. For information about our 2014 equity offerings, see Note 10 "Stockholders' Equity–––Non-Controlling Interests—Contributions" to our consolidated financial statements.

2015 Outlook

- We expect to declare dividends of $2.00 per share for 2015, a 15% increase over our 2014 declared dividend of $1.74 per share. Growth in 2015 cash dividends is expected to be driven by continued high demand for North American energy infrastructure, including the transportation and storage of natural gas, NGL, crude oil and refined products. Additionally, growth is expected to be driven by contributions from our expansion projects across our business units.

We expect that a full-year of contributions from our 2014 acquisitions and expansions, including cash tax benefits from the Merger Transactions, along with partial-year contributions from our anticipated 2015 expansion investments, as described above under —Recent Developments, will help drive earnings and cash flow growth in 2015 and beyond. Generally, our base cash flows (that is, cash flows not attributable to acquisitions or expansions) are relatively stable from year to year and are largely supported by multi-year, fee-based customer arrangements.

The overwhelming majority of cash generated by our assets is fee-based and is not sensitive to commodity prices. We do have some commodity price sensitivity, primarily in our CO_2 segment, and hedge the majority of our next twelve months of oil production to minimize this sensitivity. For 2015, we estimate that every $1 per barrel change in average WTI crude oil price impacts distributable cash flow by approximately $10 million (budget assumes average WTI price of $70 per barrel), and each $0.10 per MMBtu change in the average price of natural gas impacts distributable cash flow by approximately $3 million (budget assumes average natural gas price of $3.80 per MMBtu). This assumes we do not add additional hedges during the year which could reduce these sensitivities. These sensitivities compare to total anticipated segment earnings before DD&A in 2015 of approximately $8 billion (adding back our share of joint venture DD&A).

In addition, our expectations for 2015 discussed above involve risks, uncertainties and assumptions, and are not guarantees of performance. Many of the factors that will determine these expectations are beyond our ability to control or predict, and because of these uncertainties, it is advisable to not put undue reliance on any forward-looking statement. Please read our Item 1A "Risk Factors" below for more information. Furthermore, we plan to provide updates to our 2015 expectations when we believe previously disclosed expectations no longer have a reasonable basis.

(b) Financial Information about Segments

For financial information on our six reportable business segments, see Note 15 “Reportable Segments” to our consolidated financial statements.

(c) Narrative Description of Business

Business Strategy

Our business strategy is to:

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

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

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

Business Segments

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

- Natural Gas Pipelines—(i) the ownership and operation of major interstate and intrastate natural gas pipeline and storage systems; (ii) the ownership and/or operation of associated natural gas and crude oil gathering systems and natural gas processing and treating facilities; and (iii) the ownership and/or operation of NGL fractionation facilities and transportation systems;
- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium for recovering crude oil from mature oil fields to increase production; (ii) ownership interests in and/or operation of oil fields and gas processing plants in West Texas; and (iii) the ownership and operation of a crude oil pipeline system in West Texas;
- Terminals—(i) the ownership and/or operation of liquids and bulk terminal facilities and rail transloading and materials handling facilities located throughout the U.S. and portions of Canada that transload and store refined petroleum products, crude oil, condensate, and bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals and (ii) the ownership and operation of our Jones Act tankers;
- Products Pipelines—the ownership and operation of refined petroleum products and crude oil and condensate pipelines that deliver refined petroleum products (gasoline, diesel fuel and jet fuel), NGL, crude oil, condensate and bio-fuels to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities;
- Kinder Morgan Canada—the ownership and operation of the Trans Mountain pipeline system that transports crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia, Canada and the state of Washington, plus the Jet Fuel aviation turbine fuel pipeline that serves the Vancouver (Canada) International Airport; and
- Other—primarily includes other miscellaneous assets and liabilities purchased in our 2012 EP acquisition including (i) our corporate headquarters in Houston, Texas; (ii) several physical natural gas contracts with power plants associated with EP’s legacy trading activities; and (iii) other miscellaneous EP assets and liabilities.

Natural Gas Pipelines

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

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Our primary businesses in this segment consist of natural gas sales, transportation, storage, gathering, processing and treating, and the terminaling of LNG. Within this segment, are: (i) approximately 48,000 miles of natural gas pipelines and (ii) our equity interests in entities that have approximately 19,000 miles of natural gas pipelines, along with associated storage and supply lines for these transportation networks, which are strategically located throughout the North American natural gas pipeline grid. Our transportation network provides access to the major natural gas supply areas and consumers in the western U.S., Louisiana, Texas, the Midwest, Northeast, Rocky Mountain, Midwest and Southeastern regions. Our LNG storage and regasification terminals also serve natural gas supply areas in the southeast. The following tables summarize our significant Natural Gas Pipelines segment assets, as of December 31, 2014. The Design Capacity represents either transmission or gathering capacity depending on the nature of the asset.

	Ownership Interest %	Miles of Pipeline	Design (Bcf/d) [Storage (Bcf)] Capacity	Supply and Market Region
Natural Gas Pipelines				
TGP	100	11,900	9.00 [97]	South Texas and Gulf of Mexico to northeast and southeast U.S.; Haynesville, Marcellus, Utica, and Eagle Ford shale formations
EPNG/Mojave pipeline system	100	10,700	5.65 [44]	Northern New Mexico, Texas, Oklahoma, to California, connects to San Juan, Permian, and Anadarko basins
NGPL	20	9,200	6.20 [288]	Chicago and other Midwest markets and all central U.S. supply basins
SNG	100	6,900	3.90 [68]	Texas, Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee; basins in Texas, Louisiana, Mississippi and Alabama
Florida Gas Transmission (Citrus)	50	5,300	3.60	Texas to Florida; basins along Louisiana and Texas Gulf Coast, Mobile Bay and offshore Gulf of Mexico
CIG	100	4,300	5.20 [43]	Colorado and Wyoming; Rocky Mountains and the Anadarko Basin
WIC	100	850	3.90	Wyoming, Colorado, and Utah; Overthrust, Piceance, Uinta, Powder River and Green River Basins
Ruby pipeline	50	680	1.50	Wyoming to Oregon; Rocky Mountain basins
MEP	50	510	1.80	Oklahoma and north Texas supply basins to interconnects with deliveries to interconnects with Transco, Columbia Gulf and various other pipelines
CPG	100	410	1.20	Colorado and Kansas, natural gas basins in the Central Rocky Mountain area
TransColorado Gas	100	310	1.00	Colorado and New Mexico; connects to San Juan, Paradox and Piceance basins
WYCO	50	224	1.20 [7]	Northeast Colorado; connects with High Plains
Elba Express	100	200	0.95	Georgia; connects to SNG (Georgia), Transco (Georgia/South Carolina) and CGT (Georgia).
FEP	50	185	2.00	Arkansas to Mississippi; connects to NGPL, Trunkline Gas Company, Texas Gas Transmission, and ANR Pipeline Company
KM Louisiana	100	135	3.20	sources gas from Cheniere Sabine Pass LNG terminal to interconnects with Columbia Gulf, ANR and various

				other pipelines
Sierrita pipeline	35	60	0.20	near Tucson, Arizona, to the U.S.-Mexico border near Sasabe, Arizona; connects to EPNG and via a new international border crossing with a new natural gas pipeline in Mexico
Young Gas Storage	48	17	[6]	Morgan County, Colorado, capacity is committed to CIG and Colorado Springs Utilities.
Keystone Gas Storage	100	12	[9]	located in the Permian Basin and near the WAHA natural gas trading hub in West Texas.
Gulf LNG Holdings	50	5	[7]	near Pascagoula, Mississippi; connects to four interstate pipelines and natural gas processing plant
Bear Creek Storage	100	—	[59]	50% SNG and 50% TGP

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	Ownership Interest %	Miles of Pipeline	Design (Bcf/d) [Storage (Bcf)] Capacity	Supply and Market Region
SLNG	100	—	[12]	Georgia; connects to Elba Express, SNG and CGT
ELC	51	—		not in service until 2017 - 2018
Midstream group				
KM Texas and Tejas pipelines(a)	100	5,800	6.20 [120]	Texas Gulf Coast.
Mier-Monterrey pipeline	100	95	0.65	Starr County, Texas to Monterrey, Mexico; connects to Pemex NG Transportation system and a 1,000-megawatt power plant
KM North Texas pipeline	100	80	0.33	interconnect from NGPL; connects to 1,750-megawatt Forney, Texas, power plant and a 1,000-megawatt Paris, Texas, power plant
Copano Oklahoma				
Southern Dome	70	—	0.03	propane refrigeration plant in the southern portion of Oklahoma county
Copano Oklahoma System	100	3,500	0.38	Hunton Dewatering, Woodford Shale, and Mississippi Lime
Copano South Texas				
Webb/Duval gas gathering system	63	145	0.15	South Texas
Copano South Texas System	100	1,255	1.88	Eagle Ford shale formation, Woodbine and Eaglebine (Texas)
EagleHawk	25	860	1.00	South Texas, Eagle Ford shale formation
KM Altamont	100	790	0.08	Utah, Uinta Basin
Red Cedar	49	750	0.70	La Plata County, Colorado, Ignacio Blanco Field
Copano Rocky Mountain				
Fort Union	37	310	1.25	Powder River Basin (Wyoming)
Bighorn	51	290	0.60	Powder River Basin (Wyoming)
KinderHawk	100	500	2.00	Northwest Louisiana, Haynesville and Bossier shale formations
Copano North Texas	100	400	0.14	North Barnett Shale Combo
Endeavor	40	100	0.12	East Texas, Cotton Valley Sands and Haynesville/ Bossier Shale horizontal well developments
Camino Real - Gas	100	70	0.15	South Texas, Eagle Ford shale formation
KM Treating	100	—	—	Odessa, Texas, other locations in Tyler and Victoria, Texas
			(MBbl/d)	
Copano Liquids				
Liberty Pipeline	50	87	170	Houston Central complex to the Texas Gulf Coast
Copano Liquids Assets	100	313	115	Houston Central complex to the Texas Gulf Coast
Camino Real - Oil	100	70	110	South Texas, Eagle Ford shale formation

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Competition

The market for supply of natural gas is highly competitive, and new pipelines, storage facilities, treating facilities, and facilities for related services are currently being built to serve the growing demand for natural gas in each of the markets served by the pipelines in our Natural Gas Pipelines business segment. These operations compete with interstate and intrastate

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pipelines, and their shippers, for connections to new markets and supplies and for transportation, processing and treating services. We believe the principal elements of competition in our various markets are location, rates, terms of service and flexibility and reliability of service. From time to time, other projects are proposed that would compete with us. We do not know whether or when any such projects would be built, or the extent of their impact on our operations or profitability.

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

CO_2

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

Oil and Gas Producing Activities

Oil Producing Interests

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

	Working Interest %	KM Gross Developed Acres
SACROC	97	49,156
Yates	50	9,576
Goldsmith Landreth San Andres(a)	99	6,166
Katz Strawn	99	7,194
Sharon Ridge	14	2,619
H.T. Boyd(b)	21	n/a
MidCross	13	320
Reinecke(c)	—	80

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(a) Acquired June 1, 2013
(b) Net profits interest
(c) Working interest less than 1 percent.

The following table sets forth productive wells, service wells and drilling wells in the oil and gas fields in which we owned interests as of December 31, 2014. The oil and gas producing fields in which we own interests are located in the Permian Basin area of West Texas. When used with respect to acres or wells, “gross” refers to the total acres or wells in which we have a working interest, and “net” refers to gross acres or wells multiplied, in each case, by the percentage working interest owned by us:

	Productive Wells(a)		Service Wells(b)		Drilling Wells(c)	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	2,164	1,381	1,152	903	2	2
Natural Gas	5	2	—	—	—	—

Total Wells	2,169	1,383	1,152	903	2	2

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(a) Includes active wells and wells temporarily shut-in. As of December 31, 2014, we did not operate any productive wells with multiple completions.

(b) Consists of injection, water supply, disposal wells and service wells temporarily shut-in. A disposal well is used for disposal of salt water into an underground formation; and an injection well is a well drilled in a known oil field in order to inject liquids and/or gases that enhance recovery.

(c) Consists of development wells in the process of being drilled as of December 31, 2014. A development well is a well drilled in an already discovered oil field.

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The following table reflects our net productive wells that were completed in each of the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012
Productive			
Development	83	51	59
Exploratory	26	4	—
Total Productive	109	55	59
Dry Exploratory	1	—	—
Total Wells	110	55	59

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Note: The above table includes wells that were completed during each year regardless of the year in which drilling was initiated, and does not include any wells where drilling operations were not completed as of the end of the applicable year. A development well is a well drilled in an already discovered oil field.

The following table reflects the developed and undeveloped oil and gas acreage that we held as of December 31, 2014:

	Gross	Net
Developed Acres	75,111	71,919
Undeveloped Acres	17,603	15,369
Total	92,714	87,288

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Note: As of December 31, 2014, we have no material amount of acreage expiring in the next three years.

See "Supplemental Information on Oil and Gas Activities (Unaudited)" for additional information with respect to operating statistics and supplemental information on our oil and gas producing activities.

Gas and Gasoline Plant Interests

Operated gas plants in the Permian Basin of West Texas:

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

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

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Sales and Transportation Activities

CO_2 Segment Storage and Sales

Our principal market for CO_2 is for injection into mature oil fields in the Permian Basin, where industry demand is expected to remain strong for the next several years. Our ownership of CO_2 reserves as of December 31, 2014 includes:

	Ownership Interest %	Recoverable CO_2 (Bcf)	Compression Capacity (Bcf/d)	Location
Recoverable CO_2				
McElmo Dome unit(a)	45	5,900	1.4	Colorado
St. Johns CO_2 source field and related assets(b)	100	1,660	0.3	Apache County, Arizona, and Catron County, New Mexico
Doe Canyon Deep unit(a)	87	832	0.2	Colorado
Bravo Dome unit	11	702	0.3	New Mexico

(a) We also operate.
(b) Compression installation planned for the fourth quarter of 2018.

CO_2 Segment Pipelines

The principal market for transportation on our CO_2 pipelines is to customers, including ourselves, using CO_2 for enhanced recovery operations in mature oil fields in the Permian Basin, where industry demand is expected to remain stable for the next several years. The tariffs charged by our CO_2 pipelines are not regulated; however, the tariff charged on the Cortez pipeline is based on a consent decree. The tariffs charged on the Wink pipeline system are regulated by both the FERC and the Texas Railroad Commission. Our ownership of CO_2 and crude oil pipelines as of December 31, 2014 includes:

	Ownership Interest %	Miles of Pipeline	Transport Capacity(Bcf/d)	Supply and Market Region
CO_2 pipelines				
Cortez pipeline	50	565	1.2	McElmo Dome and Doe Canyon source fields to the Denver City, Texas hub
Central Basin pipeline	100	323	0.7	Cortez, Bravo, Sheep Mountain, Canyon Reef Carriers, and Pecos pipelines
Bravo pipeline(a)	13	218	0.4	Bravo Dome to the Denver City, Texas hub
Canyon Reef Carriers pipeline	98	162	0.3	McCamey, Texas, to the SACROC, Sharon Ridge, Cogdell and Reinecke units
Centerline CO_2 pipeline	100	112	0.3	between Denver City, Texas and Snyder, Texas
Eastern Shelf CO_2 pipeline	100	91	0.1	between Snyder, Texas and Knox City, Texas
Pecos pipeline	69	25	0.1	McCamey, Texas, to Iraan, Texas, delivers to the Yates unit
Goldsmith Landreth	99	3	0.2	Goldsmith Landreth San Andres field in the Permian Basin of West Texas
			(MBbl/d)	
Crude oil pipeline				
Wink pipeline	100	453	145	West Texas to Western Refining’s refinery in El Paso, Texas

(a) We do not operate Bravo pipeline.

Competition

Our primary competitors for the sale of CO_2 include suppliers that have an ownership interest in McElmo Dome, Bravo Dome and Sheep Mountain CO_2 resources, and Oxy U.S.A., Inc., which controls waste CO_2 extracted from natural gas production in the Val Verde Basin of West Texas. Our ownership interests in the Central Basin, Cortez and Bravo pipelines are

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in direct competition with other CO_2 pipelines. We also compete with other interest owners in the McElmo Dome unit and the Bravo Dome unit for transportation of CO_2 to the Denver City, Texas market area.

Terminals

Our Terminals segment includes the operations of our petroleum, chemical, ethanol and other liquids terminal facilities (other than those included in the Products Pipelines segment) and all of our coal, petroleum coke, fertilizer, steel, ores and other dry-bulk material services facilities, including all transload, engineering, conveying and other in-plant services. Our terminals are located throughout the U.S. and in portions of Canada. We believe the location of our facilities and our ability to provide flexibility to customers help attract new and retain existing customers at our terminals and provide us opportunities for expansion. We often classify our terminal operations based on the handling of either liquids or dry-bulk material products. In addition, we have Jones Act qualified product tankers that provide marine transportation of crude oil, condensate and refined products in the U.S. The following summarizes our Terminals segment assets, as of December 31, 2014:

	Number	Capacity (MMBbl)
Liquids terminals	39	78.0
Bulk terminals	78	n/a
Materials Services locations	8	n/a
Jones Act qualified tankers	7	2.3

Competition

We are one of the largest independent operators of liquids terminals in the U.S, based on barrels of liquids terminaling capacity. Our liquids terminals compete with other publicly or privately held independent liquids terminals, and terminals owned by oil, chemical and pipeline companies. Our bulk terminals compete with numerous independent terminal operators, terminals owned by producers and distributors of bulk commodities, stevedoring companies and other industrial companies opting not to outsource terminal services. In some locations, competitors are smaller, independent operators with lower cost structures. Our rail transloading (material services) operations compete with a variety of single- or multi-site transload, warehouse and terminal operators across the U.S. Our Jones Act qualified product tankers compete with other Jones Act qualified vessel fleets.

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Products Pipelines

Our Products Pipelines segment consists of our refined petroleum products, crude oil and condensate, and NGL pipelines and associated terminals, Southeast terminals, and our transmix processing facilities. The following summarizes our significant Products Pipelines segment assets we own and operate as of December 31, 2014:

	Ownership Interest %	Miles of Pipeline	Number of Terminals (a) or locations	Terminal Capacity(MMBbl)	Supply and Market Region
Plantation pipeline	51	3,182			Louisiana to Washington D.C.
West Coast Products Pipelines(b)					
Pacific (SFPP)	100	2,823	13	15.3	six western states
Calnev	100	570	2	2.1	Colton, CA to Las Vegas, NV; Mojave region
West Coast Terminals	100	43	6	9.2	Seattle, Portland, San Francisco and Los Angeles areas
Cochin pipeline	100	1,877	5	1.1	three provinces in Canada and seven states in the U.S.
KM Crude & Condensate pipeline	100	252	2	1.2	Eagle Ford shale field in South Texas (Dewitt County) to the Houston ship channel refining complex
Central Florida pipeline	100	206	2	2.5	Tampa to Orlando
Double Eagle pipeline	50	194		0.4	Live Oak County, Texas; Corpus Christi, Texas; Karnes County, Texas; and LaSalle County
Parkway	50	140			interconnect at Collins with Plantation and Plantation markets
Cypress pipeline	50	104			Mont Belvieu, Texas to Lake Charles, Louisiana
Southeast Terminals	100		28	9.1	from Mississippi through Virginia, including Tennessee
Kinder Morgan Assessment Protocol (KMAP)	100				pipeline integrity analysis protocol for KM and outside customers
Transmix Operations	100		6	1.5	Colton, California; Richmond, Virginia; Dorsey Junction, Maryland; Indianola, Pennsylvania; St. Louis, Missouri; and Greensboro, North Carolina

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

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

Competition

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

Kinder Morgan Canada

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

Trans Mountain Pipeline System

The Trans Mountain pipeline system originates at Edmonton, Alberta and transports crude oil and refined petroleum products to destinations in the interior and on the west coast of British Columbia. The Trans Mountain pipeline is 713 miles in length. We also own and operate a connecting pipeline that delivers crude oil to refineries in the state of Washington. The

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capacity of the line at Edmonton ranges from 300 MBbl/d when heavy crude oil represents 20% of the total throughput (which is a historically normal heavy crude oil percentage), to 400 MBbl/d with no heavy crude oil.

Jet Fuel Pipeline System

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

Competition

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

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

Other

During 2014, our other segment activity primarily includes other miscellaneous assets and liabilities purchased in our 2012 EP acquisition including (i) our corporate headquarters in Houston, Texas; (ii) several physical natural gas contracts with power plants associated with EP's legacy trading activities; and (iii) other miscellaneous EP assets and liabilities.

Major Customers

Our revenue is derived from a wide customer base. For each of the years ended December 31, 2014, 2013 and 2012, no revenues from transactions with a single external customer accounted for 10% or more of our total consolidated revenues. Our Texas intrastate natural gas pipeline group buys and sells significant volumes of natural gas within the state of Texas, and, to a far lesser extent, the CO_2 business segment also sells natural gas. Combined, total revenues from the sales of natural gas from the Natural Gas Pipelines and CO_2 business segments in 2014, 2013 and 2012 accounted for 25%, 28% and 28%, respectively, of our total consolidated revenues. To the extent possible, we attempt to balance the pricing and timing of our natural gas purchases to our natural gas sales, and these contracts are often settled in terms of an index price for both purchases and sales. We do not believe that a loss of revenues from any single customer would have a material adverse effect on our business, financial position, results of operations or cash flows.

Regulation
Interstate Common Carrier Refined Petroleum Products and Oil Pipeline Rate Regulation - U.S. Operations
Some of our U.S. refined petroleum products and crude oil pipelines are interstate common carrier pipelines, subject to regulation by the FERC under the Interstate Commerce Act, or ICA. The ICA requires that we maintain our tariffs on file with the FERC. Those tariffs set forth the rates we charge for providing transportation services on our interstate

common carrier pipelines as well as the rules and regulations governing these services. The ICA requires, among other things, that such rates on interstate common carrier pipelines be “just and reasonable” and nondiscriminatory. The ICA permits interested persons to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff collected during the pendency of the investigation. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained during the two years prior to the filing of a complaint.

On October 24, 1992, Congress passed the Energy Policy Act of 1992. The Energy Policy Act deemed petroleum products pipeline tariff rates that were in effect for the 365-day period ending on the date of enactment or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period to be just and reasonable or “grandfathered” under the ICA. The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. Certain rates on our Pacific operations’ pipeline system were subject to protest during the 365-day period established by the Energy Policy Act. Accordingly, certain of the Pacific pipelines’ rates have been, and continue to be, the subject of complaints with the FERC, as is more fully described in Note 16 “Litigation, Environmental and Other” to our consolidated financial statements.

Petroleum products pipelines may change their rates within prescribed ceiling levels that are tied to an inflation index. Shippers may protest rate increases made within the ceiling levels, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline’s increase in costs from the previous year. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. Cost-of-service ratemaking, market-based rates and settlement rates are alternatives to the indexing approach and may be used in certain specified circumstances to change rates.

Common Carrier Pipeline Rate Regulation - Canadian Operations

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

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

Interstate Natural Gas Transportation and Storage Regulation

Posted tariff rates set the general range of maximum and minimum rates we charge shippers on our interstate natural gas pipelines. Within that range, each pipeline is permitted to charge discounted rates to meet competition, so long as such discounts are offered to all similarly situated shippers and granted without undue discrimination. Apart from discounted rates offered within the range of tariff maximums and minimums, the pipeline is permitted to offer negotiated rates where the pipeline and shippers want rate certainty, irrespective of changes that may occur to the range of tariff-based maximum and minimum rate levels. Negotiated rates provide certainty to the pipeline and the shipper of a fixed rate during the term of the transportation agreement, regardless of changes to the posted tariff rates. There are a variety of rates that different shippers may pay, and while rates may vary by shipper and circumstance, the terms and conditions of pipeline transportation and storage services are not generally negotiable.

The FERC regulates the rates, terms and conditions of service, construction and abandonment of facilities by companies performing interstate natural gas transportation services, including storage services, under the Natural Gas Act of 1938. To a lesser extent, the FERC regulates interstate transportation rates, terms and conditions of service under the Natural Gas Policy Act of 1978. Beginning in the mid-1980’s, through the mid-1990’s, the FERC initiated a number of regulatory changes intended to create a more competitive environment in the natural gas marketplace. Among the most important of these changes were:

- Order No. 436 (1985) which required open-access, nondiscriminatory transportation of natural gas;
- Order No. 497 (1988) which set forth new standards and guidelines imposing certain constraints on the interaction between interstate natural gas pipelines and their marketing affiliates and imposing certain disclosure requirements regarding that interaction; and
- Order No. 636 (1992) which required interstate natural gas pipelines that perform open-access transportation under blanket certificates to “unbundle” or separate their traditional merchant sales services from their transportation and storage services and to provide comparable transportation and storage services with respect to all natural gas supplies. Natural gas pipelines must now separately state the applicable rates for each unbundled service they provide (i.e., for the natural gas commodity, transportation and storage).

The FERC standards of conduct address and clarify multiple issues, including (i) the definition of transmission function and transmission function employees; (ii) the definition of marketing function and marketing function employees; (iii) the definition of transmission function information; (iv) independent functioning; (v) transparency; and (vi) the interaction of

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FERC standards with the North American Energy Standards Board business practice standards. The FERC also promulgates certain standards of conduct that apply uniformly to interstate natural gas pipelines and public utilities. In light of the changing structure of the energy industry, these standards of conduct govern employee relationships-using a functional approach-to ensure that natural gas transmission is provided on a nondiscriminatory basis. Pursuant to the FERC's standards of conduct, a natural gas transmission provider is prohibited from disclosing to a marketing function employee non-public information about the transmission system or a transmission customer. Additionally, no-conduit provisions prohibit a transmission function provider from disclosing non-public information to marketing function employees by using a third party conduit.

Rules also require that a transmission provider provide annual training on the standards of conduct to all transmission function employees, marketing function employees, officers, directors, supervisory employees, and any other employees likely to become privy to transmission function information.

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

CPUC Rate Regulation

The intrastate common carrier operations of our Pacific operations' pipelines in California are subject to regulation by the CPUC under a "depreciated book plant" methodology, which is based on an original cost measure of investment. Intrastate tariffs filed by us with the CPUC have been established on the basis of revenues, expenses and investments allocated as applicable to the California intrastate portion of the Pacific operations' business. Tariff rates with respect to intrastate pipeline service in California are subject to challenge by complaint by interested parties or by independent action of the CPUC. A variety of factors can affect the rates of return permitted by the CPUC, and certain other issues similar to those which have arisen with respect to our FERC regulated rates also could arise with respect to its intrastate rates. The intrastate rates for movements in California on our SFPP and Calnev systems have been, and may in the future be, subject to complaints before the CPUC, as is more fully described in Note 16 "Litigation, Environmental and Other" to our consolidated financial statements.

Texas Railroad Commission Rate Regulation

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

Mexico - Energy Regulating Commission

The Mier-Monterrey Pipeline has a natural gas transportation permit granted by the Energy Regulating Commission (the Commission) that defines the conditions for the pipeline to carry out activity and provide natural gas transportation service. This permit expires in 2032.

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

Safety Regulation

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

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

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

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

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

State and Local Regulation

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

Marine Operations

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

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

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

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

Environmental Matters

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

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

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

We believe that the ultimate resolution of these environmental matters will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, it is possible that our ultimate liability with respect to these environmental matters could exceed the amounts accrued in an amount that could be material to our business, financial position, results of operations or cash flows in any particular reporting period. We have accrued an environmental reserve in the amount of $340 million as of December 31, 2014. Our reserve estimates range in value from approximately $340 million to approximately $514 million, and we recorded our liability equal to the low end of the range, as we did not identify any amounts within the range as a better estimate of the liability. For additional information related to environmental matters, see Note 16 “Litigation, Environmental and Other” to our consolidated financial statements.

Hazardous and Non-Hazardous Waste

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

Superfund

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

Clean Air Act

Our operations are subject to the Clean Air Act, its implementing regulations, and analogous state and Canadian statutes and regulations. We believe that the operations of our pipelines, storage facilities and terminals are in substantial compliance with such statutes. The EPA regulations under the Clean Air Act contain requirements for the monitoring, reporting, and control of greenhouse gas emissions from stationary sources. For further information, see “—Climate Change” below.

Clean Water Act

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

Climate Change

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

Beginning in December 2009, EPA published several findings and rulemakings under the Clean Air Act requiring the permitting and reporting of certain greenhouse gases including CO_2 and methane. Our facilities are subject to and in substantial compliance with these requirements. Operational and/or regulatory changes could require additional facilities to comply with greenhouse gas emissions reporting and permitting requirements. Additionally, the EPA has announced that it will propose new regulations of greenhouse gases addressing emission of greenhouse gases with a renewed focus on emissions of methane which may impose further requirements, including emission control requirements, on Kinder Morgan facilities.

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

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

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

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

Department of Homeland Security

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

Other

Employees

We employed 11,535 full-time people at December 31, 2014, including approximately 828 full-time hourly personnel at certain terminals and pipelines covered by collective bargaining agreements that expire between 2015 and 2018. We consider relations with our employees to be good.

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

Properties

We believe that we generally have satisfactory title to the properties we own and use in our businesses, subject to liens for current taxes, liens incident to minor encumbrances, and easements and restrictions, which do not materially detract from the value of such property, the interests in those properties or the use of such properties in our businesses. Our terminals, storage

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facilities, treating and processing plants, regulator and compressor stations, oil and gas wells, offices and related facilities are located on real property owned or leased by us. In some cases, the real property we lease is on federal, state, provincial or local government land.

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

(d) Financial Information about Geographic Areas

For geographic information concerning our assets and operations, see Note 15 "Reportable Segments" to our consolidated financial statements.

(e) Available Information

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

Item 1A. Risk Factors.

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

Risks Related to Our Business

Our pipelines business is dependent on the supply of and demand for the commodities transported by our pipelines.

Our pipelines depend on production of natural gas, oil and other products in the areas served by our pipelines. Without reserve additions, production will decline over time as reserves are depleted and production costs may rise. Producers may shut down production at lower product prices or higher production costs, especially where the existing cost of production exceeds other extraction methodologies, such as in the Alberta oil sands. Producers in areas served by us may not be successful in exploring for and developing additional reserves, and our gas plants and pipelines may not be able to maintain existing volumes of throughput. Commodity prices and tax incentives may not remain at levels that encourage producers to explore for and develop additional reserves, produce existing marginal reserves or renew transportation contracts as they expire.

Changes in the business environment, such as the recent sharp decline in crude oil prices, an increase in production costs from higher feedstock prices, supply disruptions, or higher development costs, could result in a slowing of supply from oil and natural gas producing areas. In addition, changes in the regulatory environment or governmental policies may have an impact on the supply of crude oil and natural gas. Each of these factors impacts our customers shipping through our pipelines, which in turn could impact the prospects of new transportation contracts or renewals of existing contracts.

Throughput on our crude oil, natural gas and refined petroleum products pipelines also may decline as a result of changes in business conditions. Over the long term, business will depend, in part, on the level of demand for oil, natural gas and refined petroleum products in the geographic areas in which deliveries are made by pipelines and the ability and willingness of shippers having access or rights to utilize the pipelines to supply such demand.

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

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

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

Our growth strategy may cause difficulties integrating acquisitions and constructing new facilities, and we may not be able to achieve the expected benefits from any future acquisitions or expansions.

Part of our business strategy includes acquiring additional businesses, expanding existing assets and constructing new facilities. If we do not successfully integrate acquisitions, expansions or newly constructed facilities, we may not realize anticipated operating advantages and cost savings. The integration of acquired companies or new assets involves a number of risks, including (i) demands on management related to the increase in our size; (ii) the diversion of management’s attention from the management of daily operations; (iii) difficulties in implementing or unanticipated costs of accounting, estimating, reporting and other systems; (iv) difficulties in the assimilation and retention of necessary employees; and (v) potential adverse effects on operating results.

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

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

As of December 31, 2014, we had approximately $41 billion of consolidated debt (excluding debt fair value adjustments). Additionally, in connection with the Merger Transactions, we and substantially all of our wholly owned subsidiaries entered into a cross guarantee agreement whereby each party to the agreement unconditionally guarantees the indebtedness of each other party to the agreement, thereby causing us to become liable for the debt of each of such subsidiaries. This level of debt and the cross guarantee agreement could have important consequences, such as (i) limiting our ability to obtain additional financing to fund our working capital, capital expenditures, debt service requirements or potential growth or for other purposes; (ii) increasing the cost of our future borrowings; (iii) limiting our ability to use operating cash flow in other areas of our business or to pay dividends because we must dedicate a substantial portion of these funds to make payments on our debt; (iv) placing us at a competitive disadvantage compared to competitors with less debt; and (v) increasing our vulnerability to adverse economic and industry conditions.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond our control. If our operating results are not sufficient to service our indebtedness, including the cross-guaranteed debt, and any future indebtedness that we incur, we will be forced to take actions, which may include reducing dividends, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to affect any of these actions on satisfactory terms or at all. For more information about our debt, see Note 8 “Debt” to our consolidated financial statements.

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New regulations, rulemaking and oversight, as well as changes in regulations, by regulatory agencies having jurisdiction over our operations could adversely impact our income and operations.

Our assets and operations are subject to regulation and oversight by federal, state, provincial and local regulatory authorities. Regulatory actions taken by these agencies have the potential to adversely affect our profitability. Regulation affects almost every part of our business and extends to such matters as (i) rates (which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for), operating terms and conditions of service; (ii) the types of services we may offer to our customers; (iii) the contracts for service entered into with our customers; (iv) the certification and construction of new facilities; (v) the integrity, safety and security of facilities and operations; (vi) the acquisition of other businesses; (vii) the acquisition, extension, disposition or abandonment of services or facilities; (viii) reporting and information posting requirements; (ix) the maintenance of accounts and records; and (x) relationships with affiliated companies involved in various aspects of the natural gas and energy businesses.

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

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

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

Our existing rates may also be challenged by complaint. Regulators and shippers on our pipelines have rights to challenge, and have challenged, the rates we charge under certain circumstances prescribed by applicable regulations. Some shippers on our pipelines have filed complaints with the regulators that seek substantial refunds for alleged overcharges during the years in question and prospective reductions in the tariff rates. Further, the FERC may continue to initiate investigations to determine whether interstate natural gas pipelines have over-collected on rates charged to shippers. We may face challenges, similar to those described in Note 16 to our consolidated financial statements, to the rates we charge on our pipelines. Any successful challenge to our rates could materially adversely affect our future earnings, cash flows and financial condition.

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

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

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

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

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

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

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

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

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

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

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

Methane, a primary component of natural gas, and CO_2, which is naturally occurring and also a byproduct of the burning of natural gas, are examples of greenhouse gases. The EPA regulates greenhouse gas emissions and requires the reporting of greenhouse gas emissions in the U.S. for emissions from specified large greenhouse gas emission sources, fractionated NGL, and the production of naturally occurring CO_2, like our McElmo Dome CO_2 field, even when such production is not emitted to the atmosphere.

Because our operations, including our compressor stations and natural gas processing plants in our Natural Gas Pipelines segment, emit various types of greenhouse gases, primarily methane and CO_2, such regulation could increase our costs related to operating and maintaining our facilities and could require us to install new emission controls on our facilities, acquire allowances for our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program, and such increased costs could be significant. Recovery of such increased costs from our customers is uncertain in all cases and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC. Any of the foregoing could have adverse effects on our business, financial position, results of operations or cash flows. For more information about climate change regulation, see Items 1 and 2 “Business and Properties—(c) Narrative Description of Business—Environmental Matters—Climate Change.”

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

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

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

Our acquisition strategy and expansion programs require access to new capital. Limitations on our access to capital would impair our ability to grow.

We rely on external financing sources, including commercial borrowings and issuances of debt and equity securities, to fund our acquisition and growth capital expenditures. However, to the extent we are unable to continue to finance growth externally, our cash distribution policy will significantly impair our ability to grow. We may need new capital to finance these activities. Limitations on our access to capital, whether due to tightened capital markets, more expensive capital or otherwise, will impair our ability to execute this strategy.

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

As of December 31, 2014, approximately $11 billion of our approximately $41 billion of consolidated debt (excluding debt fair value adjustments) was subject to variable interest rates, either as short-term or long-term debt of variable rate debt obligations, or as long-term fixed-rate debt effectively converted to variable rates through the use of interest rate swaps.

Should interest rates increase, the amount of cash required to service this debt would increase and our earnings could be adversely affected. For more information about our interest rate risk, see Item 7A "Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk."

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

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

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

Adverse changes to the availability, terms and cost of capital, interest rates or our credit ratings could cause our cost of doing business to increase by limiting our access to capital, limiting our ability to pursue acquisition opportunities and reducing our cash flows. Our credit ratings may be impacted by our leverage, liquidity, credit profile and potential transactions. Also, disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations on favorable terms. A significant reduction in the availability of credit could materially and adversely affect business, financial condition and results of operations.

In addition, any reduction in our credit ratings could negatively impact the credit ratings of our subsidiaries, which could increase their cost of capital and negatively affect their business and operating results. Although the ratings from credit agencies are not recommendations to buy, sell or hold our securities, our credit ratings will generally affect the market value of our and our subsidiaries' debt securities.

Cost overruns and delays on our expansion and new build projects could adversely affect our business.

We regularly undertake major construction projects to expand our existing assets and to construct new assets. A variety of factors outside of our control, such as weather, natural disasters and difficulties in obtaining permits and rights-of-way or other regulatory approvals, as well as performance by third-party contractors, has resulted in, and may continue to result in, increased costs or delays in construction. Significant cost overruns or delays in completing a project could have a material adverse effect on our return on investment, results of operations and cash flows.

We must either obtain the right from landowners or exercise the power of eminent domain in order to use most of the land on which our pipelines are constructed, and we are subject to the possibility of increased costs to retain necessary land use.

We obtain the right to construct and operate pipelines on other owners' land for a period of time. If we were to lose these rights or be required to relocate our pipelines, our business could be negatively affected. In addition, we are subject to the possibility of increased costs under our rental agreements with landowners, primarily through rental increases and renewals of expired agreements.

Whether we have the power of eminent domain for our pipelines, other than interstate natural gas pipelines, varies from state to state depending upon the type of pipeline-petroleum liquids, natural gas, CO_2, or crude oil-and the laws of the particular state. Our interstate natural gas pipelines have federal eminent domain authority. In either case, we must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. Our inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our pipelines are located.

Current or future distressed financial conditions of our customers could have an adverse impact on us in the event these customers are unable to pay us for the products or services we provide.

Some of our customers are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. We cannot provide assurance that one or more of our financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations or future cash flows. Furthermore, the bankruptcy of one or more

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of our customers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. In addition, such events might force such customers to reduce or curtail their future use of our products and services, which could have a material adverse effect on our results of operations, financial condition, and cash flows.

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

Economic conditions worldwide have from time to time contributed to slowdowns in several industries, including the oil and gas industry, the steel industry and in specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our products and services. Our operating results in one or more geographic regions also may be affected by uncertain or changing economic conditions within that region, such as the challenges that are currently affecting economic conditions in the U.S. and Canada. Volatility in commodity prices might have an impact on many of our customers, which in turn could have a negative impact on their ability to meet their obligations to us. In addition, decreases in the prices of crude oil and NGL will have a negative impact on the results of our CO_2 business segment. If global economic and market conditions (including volatility in commodity markets), or economic conditions in the U.S. or other key markets, remain uncertain or persist, spread or deteriorate further, we may experience material impacts on our business, financial condition and results of operations.

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

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

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

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

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

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

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

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

The volatility of oil and natural gas prices could have a material adverse effect on our CO_2 and natural gas pipeline business segments.

The revenues, profitability and future growth of our CO_2 and natural gas pipeline business segments and the carrying value of its oil, NGL and natural gas properties depend to a large degree on prevailing oil and gas prices. For 2015, we estimate that every $1 change in the average WTI crude oil price per barrel would impact our distributable cash flow by approximately $10 million and each $0.10 per MMBtu change in the average price of natural gas impacts distributable cash flow by approximately $3 million. Prices for oil, NGL and natural gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil, NGL and natural gas, uncertainties within the market and a variety of other factors beyond our control. These factors include, among other things (i) weather conditions and events such as hurricanes in the U.S.; (ii) the condition of the U.S. economy; (iii) the activities of the Organization of Petroleum Exporting Countries; (iv) governmental regulation; (v) political stability in the Middle East and elsewhere; (vi) the foreign supply of and demand for oil and natural gas; (vii) the price of foreign imports; and (viii) the availability of alternative fuel sources.

A sharp decline in the prices of oil, NGL or natural gas would result in a commensurate reduction in our revenues, income and cash flows from the production of oil, NGL, and natural gas and could have a material adverse effect on the carrying value of our proved reserves. In the event prices fall substantially, we may not be able to realize a profit from our production and would operate at a loss. In recent decades, there have been periods of both worldwide overproduction and underproduction of hydrocarbons and periods of both increased and relaxed energy conservation efforts. Such conditions have resulted in periods of excess supply of, and reduced demand for, crude oil on a worldwide basis and for natural gas on a domestic basis. These periods have been followed by periods of short supply of, and increased demand for, crude oil and natural gas. The excess or short supply of crude oil or natural gas has placed pressures on prices and has resulted in dramatic price fluctuations even during relatively short periods of seasonal market demand. These fluctuations impact the accuracy of assumptions used in our budgeting process. For more information about our energy and commodity market risk, see Item 7A “Quantitative and Qualitative Disclosures About Market Risk—Energy Commodity Market Risk.”

Our use of hedging arrangements could result in financial losses or reduce our income.

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

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

The adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the OTC derivatives market and entities that participate in that market. The CFTC has proposed new rules pursuant to the Dodd-Frank Act that would institute broad new aggregate position limits for OTC swaps and futures and options traded on regulated exchanges. As the law favors exchange trading and clearing, the Dodd-Frank Act also may require us to move certain derivatives transactions to exchanges where no trade credit is provided and also comply with margin requirements in connection with our derivatives activities that are not exchange traded, although the application of those provisions to us is uncertain at this time. The Dodd-Frank Act also requires many counterparties to our derivatives instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty, or cause the entity to comply with the capital requirements, which could result in increased costs to counterparties such as us. The Dodd-Frank Act and any related regulations could (i) significantly increase the cost of derivative contracts (including those requirements to post collateral, which could adversely affect our available liquidity); (ii) reduce the availability of derivatives to protect against risks we encounter; and (iii) reduce the liquidity of energy related derivatives.

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

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

Following our 2014 acquisitions of American Petroleum Tankers, State Class Tankers, and the Pennsylvania and Florida Jones Act tankers from Crowley Maritime Corporation Tankers, we are subject to the Jones Act, which generally restricts U.S. point-to-point maritime shipping to vessels operating under the U.S. flag, built in the U.S., owned and operated by U.S.-organized companies that are controlled and at least 75% owned by U.S. citizens and manned by predominately U.S. crews. Our business would be adversely affected if we fail to comply with the Jones Act provisions on coastwise trade. If we do not comply with any of these requirements, we would be prohibited from operating our vessels in the U.S. coastwise trade and, under certain circumstances, we could be deemed to have undertaken an unapproved transfer to non-U.S. citizens that could result in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of vessels. Our business could be adversely affected if the Jones Act were to be modified or repealed so as to permit foreign competition that is not subject to the same U.S. government imposed burdens.

Our business requires the retention and recruitment of a skilled workforce and the loss of such workforce could result in the failure to implement our business plans.

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

If we are unable to retain our chairman or executive officers, our growth may be hindered.

Our success depends in part on the performance of and our ability to retain our chairman and our executive officers, particularly our Chairman and current Chief Executive Officer, Richard D. Kinder, who is also one of our founders, and our current President and Chief Operating Officer, Steve Kean, who will assume the Chief Executive Officer position in June of 2015. Along with the other members of our senior management, Mr. Kinder and Mr. Kean have been responsible for developing and executing our growth strategy. If we are not successful in retaining Mr. Kinder, Mr. Kean or our other executive officers or replacing them, our business, financial condition or results of operations could be adversely affected. We do not maintain key personnel insurance.

Our Kinder Morgan Canada segment is subject to U.S. dollar/Canadian dollar exchange rate fluctuations.

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

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Risks Related to the Ownership of Our Common Stock

The price of our common stock may be volatile, and holders of our common stock could lose a significant portion of their investments.

The market price of our common stock could be volatile, and our stockholders may not be able to resell their common stock at or above the price at which they purchased it due to fluctuations in its market price, including changes in price caused by factors unrelated to our operating performance or prospects.

Specific factors that may have a significant effect on the market price for our common stock include: (i) changes in stock market analyst recommendations or earnings estimates regarding our common stock, other companies comparable to us or companies in the industries we serve; (ii) actual or anticipated fluctuations in our operating results or future prospects; (iii) reaction to our public announcements; (iv) strategic actions taken by us or our competitors, such as acquisitions or restructurings; (v) the recruitment or departure of key personnel; (vi) new laws or regulations or new interpretations of existing laws or regulations applicable to our business and operations; (vii) changes in tax or accounting standards, policies, guidance, interpretations or principles; (viii) adverse conditions in the financial markets or general U.S. or international economic conditions, including those resulting from war, incidents of terrorism and responses to such events; and (ix) sales of common stock by us, members of our management team or significant stockholders.

Non-U.S. holders of our common stock may be subject to U.S. federal income tax with respect to gain on the disposition of our common stock.

If we are or have been a “U.S. real property holding corporation’’ within the meaning of the Code at any time within the shorter of (i) the five-year period preceding a disposition of our common stock by a non-U.S. holder or (ii) such holder’s holding period for such common stock, and assuming our common stock is “regularly traded,’’ as defined by applicable U.S. Treasury regulations, on an established securities market, the non-U.S. holder may be subject to U.S. federal income tax with respect to gain on such disposition if it held more than 5% of our common stock during the shorter of periods (i) and (ii) above. We believe we are, or may become, a U.S. real property holding corporation.

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

We disclose in this report and elsewhere our expected cash dividends. This reflects our current judgment, but as with any estimate, it may be affected by inaccurate assumptions and known and unknown risks and uncertainties, many of which are beyond our control. See “Information Regarding Forward-Looking Statements.” If the payment of dividends at the anticipated level would leave us with insufficient cash to take timely advantage of growth opportunities (including through acquisitions), to meet any large unanticipated liquidity requirements, to fund our operations, or otherwise to address properly our business prospects, our business would be harmed. Conversely, a decision to address such needs might lead to the payment of dividends below the anticipated level. As events present themselves or become reasonably foreseeable, our board of directors, which determines our business strategy and our dividends, might have to choose between addressing those matters or reducing our anticipated dividends. Alternatively, because there is nothing in our governing documents or credit agreements that prohibits us from borrowing to pay dividends, our board of directors may choose to cause us to incur debt to enable us to pay our anticipated dividends. This would add to our substantial debt discussed above under “-Risks Related to Our Business-Our substantial debt could adversely affect our financial health and make us more vulnerable to adverse economic consequences.”

Item 1B. Unresolved Staff Comments.

None.

Item 3. Legal Proceedings.

See Note 16 “Litigation, Environmental and Other” to our consolidated financial statements.

Item 4. Mine Safety Disclosures.

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

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PART II

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

On December 26, 2012, the remaining outstanding shares of our Class A, Class B, and Class C common stock were converted into Class P shares and as of December 31, 2012 only our Class P common stock was outstanding. Our Class P common stock is listed for trading on the NYSE under the symbol "KMI." During the period that our Class A, Class B, and Class C common stock was outstanding, none were traded on a public trading market. The high and low sale prices per Class P share as reported on the NYSE and the dividends declared per share by period for 2014, 2013 and 2012, are provided below.

	Price Range		Declared Cash
	Low	High	Dividends(a)
2014			
First Quarter	$30.81	$36.45	$0.42
Second Quarter	32.10	36.50	0.43
Third Quarter	35.20	42.49	0.44
Fourth Quarter	33.25	43.18	0.45
2013			
First Quarter	$35.74	$38.80	$0.38
Second Quarter	35.52	41.49	0.40
Third Quarter	34.54	40.45	0.41
Fourth Quarter	32.30	36.68	0.41
2012			
First Quarter	$31.76	$39.25	$0.32
Second Quarter	30.51	40.25	0.35
Third Quarter	32.03	36.63	0.36
Fourth Quarter	31.93	36.50	0.37

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(a) Dividend information is for dividends declared with respect to that quarter. Generally, our declared dividends are paid on or about the 16th day of each February, May, August and November.

As of February 2, 2015, we had 12,483 holders of our Class P common stock, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

For information on our equity compensation plans, see Note 9 "Share-based Compensation and Employee Benefits—Share-based Compensation—Kinder Morgan, Inc." to our consolidated financial statements.

Our Purchases of Our Class P Shares and Warrants

Period	Total number of securities purchased	Average price paid per security	Total number of securities purchased as part of publicly announced plans	Maximum number (or approximate dollar value) of securities that may yet be purchased under the plans or programs(a)
October 1 to October 31, 2014	—	$—	—	$2,452,606
November 1 to November 30, 2014	—	$—	—	$2,452,606
	—	$—	—	$2,452,606

December 1 to December 31, 2014	
	$2,452,606

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(a) Remaining amount available under a $100 million share and warrant repurchase program approved by our board of directors on March 4, 2014.

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Item 6. Selected Financial Data.

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

Five-Year Review
Kinder Morgan, Inc. and Subsidiaries

	As of or for the Year Ended December 31,				
	2014	2013	2012	2011	2010
	(In millions, except per share and ratio data)				
Income and Cash Flow Data:					
Revenues	$16,226	$14,070	$9,973	$7,943	$7,852
Operating income	4,448	3,990	2,593	1,423	1,133
Earnings (loss) from equity investments	406	327	153	226	(274)
Income from continuing operations	2,443	2,696	1,204	449	64
(Loss) income from discontinued operations, net of tax	—	(4)	(777)	211	236
Net income	2,443	2,692	427	660	300
Net income (loss) attributable to Kinder Morgan, Inc.	1,026	1,193	315	594	(41)
Class P Shares					
Basic and Diluted Earnings Per Common Share From Continuing Operations	$0.89	$1.15	$0.56	$0.70	
Basic and Diluted (Loss) Earnings Per Common Share From Discontinued Operations	—	—	(0.21)	0.04	
Total Basic and Diluted Earnings Per Common Share	$0.89	$1.15	$0.35	$0.74	
Class A Shares					
Basic and Diluted Earnings Per Common Share From Continuing Operations			$0.47	$0.64	
Basic and Diluted (Loss) Earnings Per Common Share From Discontinued Operations			(0.21)	0.04	
Total Basic and Diluted Earnings Per Common Share			$0.26	$0.68	
Basic Weighted Average Number of Shares Outstanding:					
Class P shares	1,137	1,036	461	118	
Class A shares			446	589	
Diluted Weighted Average Number of Shares Outstanding:					
Class P shares	1,137	1,036	908	708	
Class A shares			446	589	
Dividends per common share declared for the period(a)(b)	$1.74	$1.60	$1.40	$1.05	
Dividends per common share paid in the period(a)	1.70	1.56	1.34	0.74	

Balance Sheet Data (at end of period):					
Net property, plant and equipment	$38,564	$35,847	$30,996	$17,926	$17,071
Total assets	83,198	75,185	68,245	30,717	28,908
Long-term debt(c)	38,312	31,910	29,409	13,261	13,219

(a) Dividends for the fourth quarter of each year are declared and paid during the first quarter of the following year.

(b) 2011 declared dividend per share was prorated for the portion of the first quarter we were a public company ($0.14 per share). If we had been a public company for the entire year, the 2011 declared dividend would have been $1.20 per share.

(c) Excludes debt fair value adjustments. Increases to long-term debt for debt fair value adjustments totaled $1,934 million, $1,977 million, $2,591 million, $1,095 million and $594 million as of December 31, 2014, 2013, 2012, 2011, and 2010, respectively.

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the notes thereto. We prepared our consolidated financial statements in accordance with GAAP. Additional sections in this report which should be helpful to the reading of our discussion and analysis include the following: (i) a description of our business strategy found in Items 1 and 2 "Business and Properties—(c) Narrative Description of Business—Business Strategy;" (ii) a description of developments during 2014, found in Items 1 and 2 "Business and Properties—(a) General Development of Business—Recent Developments;" and (iii) a description of risk factors affecting us and our business, found in Item 1A "Risk Factors."

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

General

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

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

- creating long-term value for our shareholders.

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

Our reportable business segments are:

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

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

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Terminals—(i) the ownership and/or operation of liquids and bulk terminal facilities and rail transloading and materials handling facilities located throughout the U.S. and portions of Canada that transload and store refined petroleum products, crude oil, condensate, and bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals and (ii) the ownership and operation of our Jones Act tankers;

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

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

- Other—primarily includes other miscellaneous assets and liabilities purchased in our 2012 EP acquisition including (i) our corporate headquarters in Houston, Texas; (ii) several physical natural gas contracts with power plants associated with EP's legacy trading activities; and (iii) other miscellaneous EP assets and liabilities.

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

With respect to our interstate natural gas pipelines and related storage facilities, the revenues from these assets are primarily received under contracts with terms that are fixed for various and extended periods of time. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate risk of reduced volumes and prices by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. These long-term contracts are typically structured with a fixed-fee reserving the right to transport natural gas and specify that we receive the majority of our fee for making the capacity available, whether or not the customer actually chooses to utilize the capacity. Similarly, the Texas Intrastate Natural Gas Group, currently derives approximately 75% of its sales and transport margins from long-term transport and sales contracts that include requirements with minimum volume payment obligations. As contracts expire, we have additional exposure to the longer term trends in supply and demand for natural gas. As of December 31, 2014, the remaining average contract life of our natural gas transportation contracts (including intrastate pipelines' purchase and sales contracts) was approximately six years.

Our midstream group, which is within our Natural Gas Pipelines Segment, provides gathering and processing services primarily through our (i) EP midstream asset operations, which we acquired 50% from KKR effective June 1, 2012, and 50% from the May 25, 2012 EP acquisition, (ii) our Copano operations, which included the remaining 50% ownership interest in Eagle Ford Gathering LLC (Eagle Ford) that we did not already own and which was acquired effective May 1, 2013 and (iii) our KinderHawk operation, which gathers and treats natural gas in the Haynesville and Bossier shale gas formations located in northwest Louisiana. These substantially fee-based gathering, processing and fractionation assets, along with our financial strength and extensive pipeline transportation and storage assets, provide an excellent platform to further grow our midstream group services footprint. The revenues and earnings we realize from gathering natural gas, processing natural gas in order to remove NGL from the natural gas stream, and fractionating NGL into their base components, are also affected by the volumes of natural gas made available to our systems, which are primarily driven by levels of natural gas drilling activity. Our midstream group services are provided pursuant to a variety of arrangements, generally categorized (by the nature of the commodity price risk) as fee-based, percent-of-proceeds, percent-of-index and keep-whole. Contracts may rely solely on a single type of arrangement, but more often they combine elements of two or more of the above, which helps us and our counterparties manage the extent to which each shares in the potential risks and benefits of changing commodity prices.

In February 2015, we acquired Hiland Partners (Hiland) for a total purchase price of approximately $3 billion (including assumption of debt). Hiland's assets consist of crude oil gathering and transportation pipelines and gas gathering and processing systems, primarily serving production from the Bakken Formation in North Dakota and Montana. Most of Hiland's operations will be included in our midstream group within our Natural Gas Pipelines segment.

The CO_2 source and transportation business primarily has third-party contracts with minimum volume requirements, which as of December 31, 2014, had a remaining average contract life of approximately ten years. CO_2 sales contracts vary from customer to customer and have evolved over time as supply and demand conditions have changed. Our recent contracts have generally provided for a delivered price tied to the price of crude oil, but with a floor price. On a volume-weighted basis, for third-party contracts making deliveries in 2015, and utilizing the average oil price per barrel contained in our 2015 budget, approximately 86% of our revenue is based on a fixed fee or floor price, and 14% fluctuates with the price of oil. In the long-term, our success in this portion of the CO_2 business segment is driven by the demand for CO_2. However, short-term changes in the demand for CO_2 typically do not have a significant impact on us due to the required minimum sales volumes under many of our contracts. In the CO_2 business segment's oil and gas producing activities, we monitor the amount of capital we expend in relation to the amount of production that we expect to add. In that regard, our production during any period is an important measure. In addition, the revenues we receive from our crude oil, NGL and CO_2 sales are affected by the prices we realize from the sale of these products. Over the long-term, we will tend to receive prices that are dictated by the demand and overall market price for these products. In the shorter term, however, market prices are likely not indicative of the revenues we will receive due to our risk management, or hedging, program, in which the prices to be realized for certain of our future sales quantities are fixed, capped or bracketed through the use of financial derivative contracts, particularly for crude oil. The realized weighted average crude oil price per barrel, with all hedges allocated to oil, was $88.41 per barrel in 2014, $92.70 per barrel in 2013 and $87.72 per barrel in 2012. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $86.48 per barrel in 2014, $94.94 per barrel in 2013 and $89.91 per barrel in 2012.

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

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

Our 2015 budget, and related announced expectation to declare dividends of $2.00 per share for 2015, assumes an average WTI crude oil price of approximately $70 per barrel and an average natural gas price of $3.80 per MMBtu in 2015. For 2015, we estimate that every $1 change in the average WTI crude oil price per barrel will impact our distributable cash flow by approximately $10 million (approximately $7 million of which is attributable to our CO_2 business segment), and each $0.10 per MMBtu change in the average price of natural gas will impact distributable cash flow by approximately $3 million. This assumes we do not add additional hedges during the year which could reduce these sensitivities. These sensitivities compare to total anticipated segment earnings before DD&A in 2015 of approximately $8 billion (adding back our share of joint venture DD&A). Even adjusting for current commodity prices we expect to have significant excess coverage in 2015.

The amount that we are able to increase dividends to our shareholders will, to some extent, be a function of our ability to complete successful acquisitions and expansions. We believe we will continue to have opportunities for expansion of our facilities in many markets, and we have budgeted approximately $4.4 billion for our 2015 capital expansion program (including small acquisitions and investment contributions, but excluding our recent acquisition of Hiland Partners, LP). We consider and enter into discussions regarding potential acquisitions and are currently contemplating potential acquisitions.

Based on our historical record and because there is continued demand for energy infrastructure in the areas we serve, we expect to continue to have such opportunities in the future, although the level of such opportunities is difficult to predict. While there are currently no unannounced purchase agreements for the acquisition of any material business or assets, such transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets or operations. Furthermore, our ability to make accretive acquisitions is a function of the availability of suitable acquisition candidates at the right cost, and includes factors over which we have limited or no control. Thus, we have no way to determine the number or size of accretive acquisition candidates in the future, or whether we will complete the acquisition of any such candidates.

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Our ability to make accretive acquisitions or expand our assets is impacted by our ability to maintain adequate liquidity and to raise the necessary capital needed to fund such acquisitions. Our dividend policy is to distribute most of our available cash, and we intend to continue accessing capital markets to fund acquisitions and asset expansions. Historically, we have succeeded in raising necessary capital in order to fund our acquisitions and expansions, and although we cannot predict future changes in the overall equity and debt capital markets (in terms of tightening or loosening of credit), we believe that our stable cash flows, credit ratings, and historical records of successfully accessing both equity and debt funding sources should allow us to continue to execute our current investment, dividend and acquisition strategies, as well as refinance maturing debt when required. For a further discussion of our liquidity, including our and our subsidiaries' public debt and equity offerings in 2014, please see "—Liquidity and Capital Resources" below.

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

In addition, a portion of our business portfolio (including the Kinder Morgan Canada business segment, the Canadian portion of the Cochin Pipeline, and the bulk and liquids terminal facilities located in Canada) use the local Canadian dollar as the functional currency for its Canadian operations and we enter into foreign currency-based transactions, both of which affect segment results due to the inherent variability in U.S. - Canadian dollar exchange rates. To help understand our reported operating results, all of the following references to "foreign currency effects" or similar terms in this section represent our estimates of the changes in financial results, in U.S. dollars, resulting from fluctuations in the relative value of the Canadian dollar to the U.S. dollar. The references are made to facilitate period-to-period comparisons of business performance and may not be comparable to similarly titled measures used by other registrants.

Critical Accounting Policies and Estimates

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

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

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

Acquisition Method of Accounting

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

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Environmental Matters

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

Our recording of our environmental accruals often coincides with our completion of a feasibility study or our commitment to a formal plan of action, but generally, we recognize and/or adjust our environmental liabilities following routine reviews of potential environmental issues and claims that could impact our assets or operations. These adjustments may result in increases in environmental expenses and are primarily related to quarterly reviews of potential environmental issues and resulting environmental liability estimates. In making these liability estimations, we consider the effect of environmental compliance, pending legal actions against us, and potential third party liability claims. For more information on environmental matters, see Items 1 and 2 “Business and Properties—(c) Narrative Description of Business—Environmental Matters”. For more information on our environmental disclosures, see Note 16 “Litigation, Environmental and Other Contingencies” to our consolidated financial statements.

Legal Matters

Many of our operations are regulated by various U.S. and Canadian regulatory bodies and we are subject to legal and regulatory matters as a result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from orders, judgments or settlements. In general, we expense legal costs as incurred. When we identify contingent liabilities, we identify a range of possible costs expected to be required to resolve the matter. Generally, if no amount within this range is a better estimate than any other amount, we record a liability equal to the low end of the range. Any such liability recorded is revised as better information becomes available. Accordingly, to the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. For more information on legal proceedings, see Note 16 “Litigation, Environmental and Other Contingencies” to our consolidated financial statements.

Intangible Assets

Intangible assets are those assets which provide future economic benefit but have no physical substance. Identifiable intangible assets having indefinite useful economic lives, including goodwill, are not subject to regular periodic amortization, and such assets are not to be amortized until their lives are determined to be finite. Instead, the carrying amount of a recognized intangible asset with an indefinite useful life must be tested for impairment annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. We evaluate our goodwill for impairment on May 31 of each year. There were no impairment charges resulting from our May 31, 2014 impairment testing, and no event indicating an impairment has occurred subsequent to that date, other than $2 million associated with a pending asset divestiture. Furthermore, our analysis as of that date did not reflect any reporting units at risk, and subsequent to that date, no event has occurred indicating that the implied fair value of each of our reporting units is less than the carrying value of its net assets. For more information on our goodwill, see Notes 2 “Summary of Significant Accounting Policies” and 7 “Goodwill and Other Intangibles” to our consolidated financial statements.

Excluding goodwill, our other intangible assets include customer contracts, relationships and agreements, lease value, and technology-based assets. These intangible assets have definite lives, are being amortized in a systematic and rational manner over their estimated useful lives, and are reported separately as "Other intangibles, net" in our accompanying consolidated balance sheets. For more information on our amortizable intangibles, see Note 7 "Goodwill and Other Intangibles" to our consolidated financial statements.

Estimated Net Recoverable Quantities of Oil and Gas

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved reserves, both developed and undeveloped. The existence and the estimated amount of proved reserves affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depleted or amortized into income, and the presentation of supplemental information on oil and gas producing

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activities. The expected future cash flows to be generated by oil and gas producing properties used in testing for impairment of such properties also rely in part on estimates of net recoverable quantities of oil and gas.

Proved reserves are the estimated quantities of oil and gas that geologic and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves may change, either positively or negatively, as additional information becomes available and as contractual, economic and political conditions change. For more information on our ownership interests in the net quantities of proved oil and gas reserves and our measures of discounted future net cash flows from oil and gas reserves, please see "Supplemental Information on Oil and Gas Producing Activities (Unaudited)".

The quantities of our proved oil and gas reserves and the measures of discounted future net cash flows from those oil and gas reserves as of December 31, 2014 are based on the 12 month unweighted average of the first day of the month price realized in 2014. Commodity prices fell substantially toward the end of 2014 and therefore, unless commodity prices recover in the next 12 months, the amount of our proved oil and gas reserves and the measures of discounted future net cash flows from those oil and gas reserves could be negatively impacted in 2015. Any resulting reductions in our proved oil and gas reserves due to lower commodity pricing may increase our DD&A expense. Sustained lower commodity prices may also negatively impact forward curve pricing that is used in testing for impairment, estimated total proved and risk-adjusted probable and possible oil and gas reserves, and related expected future cash flows, which may result in impairment of our oil producing interests.

Hedging Activities

We engage in a hedging program that utilizes derivative contracts to mitigate (offset) our exposure to fluctuations in energy commodity prices and to balance our exposure to fixed and variable interest rates, and we believe that these hedges are generally effective in realizing these objectives. According to the provisions of GAAP, to be considered effective, changes in the value of a derivative contract or its resulting cash flows must substantially offset changes in the value or cash flows of the item being hedged, and any ineffective portion of the hedge gain or loss and any component excluded from the computation of the effectiveness of the derivative contract must be reported in earnings immediately. We may or may not apply hedge accounting to our derivative contracts depending on the circumstances. All of our derivative contracts are recorded at estimated fair value.

Since it is not always possible for us to engage in a hedging transaction that completely mitigates our exposure to unfavorable changes in commodity prices-a perfectly effective hedge-we often enter into hedges that are not completely effective in those instances where we believe to do so would be better than not hedging at all. But because the part of such hedging transactions that is not effective in offsetting undesired changes in commodity prices (the ineffective portion) is required to be recognized currently in earnings, our financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge. For example, when we purchase a commodity at one location and sell it at another, we may be unable to hedge completely our exposure to a differential in the price of the product between these two locations; accordingly, our financial statements may reflect some volatility due to these hedges. For more information on our hedging activities, see Note 13 "Risk Management" to our consolidated financial statements.

Employee Benefit Plans

We reflect an asset or liability for our pension and other postretirement benefit plans based on their overfunded or underfunded status. As of December 31, 2014, our pension plans were underfunded by $427 million and our other postretirement benefits plans were underfunded by $235 million. Our pension and other postretirement benefit obligations and net benefit costs are primarily based on actuarial calculations. We use various assumptions in performing these calculations, including those related to the return that we expect to earn on our plan assets, the rate at which we expect the compensation of our employees to increase over the plan term, the estimated cost of health care when benefits are provided under our plan and other factors. A significant assumption we utilize is the discount rate used in calculating our benefit obligations. We select our discount rates by matching the timing and amount of our expected future benefit payments for our pension and other postretirement benefit obligations to the average yields of various high-quality bonds with corresponding maturities. The selection of these assumptions is further discussed in Note 9 “Share-based Compensation and Employee Benefits” to our consolidated financial statements.

Actual results may differ from the assumptions included in these calculations, and as a result, our estimates associated with our pension and other postretirement benefits can be, and often are, revised in the future. The income statement impact of the changes in the assumptions on our related benefit obligations are deferred and amortized into income over either the period of

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expected future service of active participants, or over the expected future lives of inactive plan participants. We record these deferred amounts as either accumulated other comprehensive income (loss) or as a regulatory asset or liability for certain of our regulated operations. As of December 31, 2014, we had deferred net losses of approximately $323 million in pretax accumulated other comprehensive loss and noncontrolling interests related to our pension and other postretirement benefits.

The following table shows the impact of a 1% change in the primary assumptions used in our actuarial calculations associated with our pension and other postretirement benefits for the year ended December 31, 2014:

	Pension Benefits		Other Postretirement Benefits	
	Net benefit cost (income)	Change in funded status and pretax accumulated other comprehensive income (loss)	Net benefit cost (income)	Change in funded status and pretax accumulated other comprehensive income (loss)
	(In millions)			
One percent increase in:				
Discount rates	$10	$260	$2	$55
Expected return on plan assets	(23)	—	(4)	—
Rate of compensation increase	2	(13)	—	—
Health care cost trends	—	—	4	(47)
One percent decrease in:				
Discount rates	(11)	(312)	—	(65)
Expected return on plan assets	23	—	4	—
Rate of compensation increase	(1)	12	—	—
Health care cost trends	—	—	(2)	40

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Income Taxes

We record a valuation allowance to reduce our deferred tax assets to an amount that is more likely than not to be realized. While we have considered estimated future taxable income and prudent and feasible tax planning strategies in determining the amount of our valuation allowance, any change in the amount that we expect to ultimately realize will be included in income in the period in which such a determination is reached. In addition, we do business in a number of states with differing laws concerning how income subject to each state's tax structure is measured and at what effective rate such income is taxed. Therefore, we must make estimates of how our income will be apportioned among the various states in order to arrive at an overall effective tax rate. Changes in our effective rate, including any effect on previously recorded deferred taxes, are recorded in the period in which the need for such change is identified.

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

Results of Operations

Non-GAAP Measures

The non-GAAP financial measures, DCF before certain items and segment EBDA before certain items are presented below under "—Distributable Cash Flow" and "—Consolidated Earnings Results," respectively. 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 or any other GAAP measure. DCF before certain items 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

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isolation or as substitutes for an analysis of our results as reported under GAAP. Because DCF before certain items excludes some but not all items that affect net income and because DCF measures are defined differently by different companies in our industry, our DCF before certain items 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 before certain items is an overall performance metric we use to estimate the ability of our assets to generate cash flows on an ongoing basis and as a measure of cash available to pay dividends. We believe the primary measure of company performance used by us, investors and industry analysts is cash generation performance. Therefore, we believe DCF before certain items is an important measure to evaluate our operating and financial performance and to compare it with the performance of other publicly traded companies within the industry. For a discussion of our anticipated dividends for 2015, see "—Financial Condition—Cash Flows—KMI Dividends."

The table below details the reconciliation of Net Income to DCF before certain items:

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Net Income	$2,443	$2,692	$427
Add/(Subtract):			
Certain items before book tax(a)	14	(609)	1,692
Book tax certain items	(117)	(39)	(412)
Certain items after book tax	(103)	(648)	1,280
Net income before certain items	2,340	2,044	1,707
Add/(Subtract):			
Net income attributable to third-party noncontrolling interests(b)	(12)	(5)	(1)
Depreciation, depletion and amortization(c)	2,390	2,142	1,678
Book taxes(d)	840	847	584
Cash taxes(d)	(448)	(552)	(460)
Declared distributions to noncontrolling interests(e)	(2,000)	(2,355)	(1,797)
Sustaining capital expenditures(f)	(509)	(414)	(393)
Other, net(g)	17	6	93
Subtotal	278	(331)	(296)
DCF before certain items	$2,618	$1,713	$1,411
Weighted Average Shares Outstanding for Dividends(h)	1,312	1,040	908
DCF per share before certain items	$2.00	$1.65	$1.55
Declared dividend per common share	1.74	1.60	1.40

(a) Consists of certain items summarized in footnotes (b) through (e) to the "—Consolidated Earnings Results" 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 net income allocated to third-party ownership interests in consolidated subsidiaries other than our former Master Limited Partnerships.

(c)

Includes DD&A, amortization of excess cost of equity investments and our share of equity method investee's DD&A of $305 million, $297 million and $236 million in 2014, 2013 and 2012, respectively.

(d) Includes our share of equity method investee's book or cash income taxes.

(e) Represents distributions to KMP and EPB limited partner units formerly owned by the public.

(f) Includes our share of equity method investee's sustaining capital expenditures of $(59) million, $(48) million and $(51) million in 2014, 2013 and 2012, respectively.

(g) Consists primarily of book to cash timing differences related to certain defined benefit plans and other items, and for periods prior to fourth quarter 2014 includes differences between earnings and cash from our former Master Limited Partnerships.

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(h) Includes restricted shares that participate in dividends. 2014 includes the shares issued on November 26, 2014 for the Merger Transactions as if outstanding for the entire fourth quarter which differs from our GAAP presentation on our Consolidated Statement of Income.

Consolidated Earnings Results

With regard to our reportable business segments, we consider segment earnings before all DD&A expenses, and amortization of excess cost of equity investments (defined in the "—Results of Operations" tables below and sometimes referred to in this report as EBDA) to be an important measure of our success in maximizing returns to our shareholders. We also use segment EBDA internally as a measure of profit and loss used for evaluating segment performance and for deciding how to allocate resources to our six reportable business segments. EBDA may not be comparable to measures used by other companies. Additionally, EBDA should be considered in conjunction with net income and other performance measures such as operating income, income from continuing operations or operating cash flows.

Certain items included in EBDA are either not allocated to business segments or are not considered by management in its evaluation of business segment performance. In general, the items not included in segment results are interest expense, general and administrative expenses, DD&A and unallocable income taxes. These items are not controllable by our business segment operating managers and therefore are not included when we measure business segment operating performance. 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.

We currently evaluate business segment performance primarily based on segment EBDA in relation to the level of capital employed. We consider each period's EBDA to be an important measure of business segment performance for our segments. We account for intersegment sales at market prices. We account for the transfer of net assets between entities under common control by carrying forward the net assets recognized in the balance sheets of each combining entity to the balance sheet of the combined entity, and no other assets or liabilities are recognized as a result of the combination. Transfers of net assets between entities under common control do not affect the income statement of the combined entity.

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Segment EBDA(a)			
Natural Gas Pipelines	$4,259	$4,207	$2,174
CO_2	1,240	1,435	1,322
Terminals	944	836	708
Products Pipelines	856	602	668
Kinder Morgan Canada	182	424	229
Other	13	(5)	7
Total Segment EBDA(b)	7,494	7,499	5,108
DD&A expense	(2,040)	(1,806)	(1,419)
Amortization of excess cost of equity investments	(45)	(39)	(23)
Other revenues	36	36	35
General and administrative expenses(c)	(610)	(613)	(929)
Interest expense, net of unallocable interest income(d)	(1,807)	(1,688)	(1,441)
Income from continuing operations before unallocable income taxes	3,028	3,389	1,331
Unallocable income tax expense	(585)	(693)	(127)

Income from continuing operations	2,443	2,696	1,204
Loss from discontinued operations, net of tax(e)	—	(4)	(777)
Net income	2,443	2,692	427
Net income attributable to noncontrolling interests	(1,417)	(1,499)	(112)
Net income attributable to Kinder Morgan, Inc.	$1,026	$1,193	$315

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(a) Includes revenues, earnings from equity investments, allocable interest income and other, net, less operating expenses, allocable income taxes, and other income (expense). 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 earnings for the years ended December 31, 2014, 2013 and 2012 were $63 million, $49 million and $12 million, respectively.

Certain item footnotes

(b) 2014, 2013 and 2012 amounts include decrease in earnings of $45 million, increase in earnings of $573 million, and decrease in earnings of $295 million, respectively, related to the combined effect from all of the 2014, 2013 and 2012 certain items impacting continuing operations and disclosed below in our management discussion and analysis of segment results.

(c) 2014 and 2013 amounts include decrease to expense of $28 million and $8 million, and 2012 amount includes increase in expense of $366 million, respectively, related to the combined effect from all of the 2014, 2013 and 2012 certain items related to general and administrative expenses disclosed below in “—General and Administrative, Interest, and Noncontrolling Interests.”

(d) 2014 and 2013 amounts include decrease in expense of $3 million and $32 million and 2012 amount includes increase in expense of $87 million, respectively, related to the combined effect from all of the 2014, 2013 and 2012 certain items related to interest expense, net of unallocable interest income disclosed below in “—General and Administrative, Interest, and Noncontrolling Interests.”

(e) 2013 amount represents an incremental loss related to the sale of our FTC Natural Gas Pipelines disposal group effective November 1, 2012. 2012 amount includes a combined $937 million loss from the remeasurement of net assets to fair value and the sale of our disposal group and DD&A expense of $7 million.

Year Ended December 31, 2014 vs. 2013

The certain items described in footnotes (b), (c) and (d) to the tables above accounted for $627 million decrease in income from continuing operations before unallocable income taxes in 2014, when compared to 2013 (combining to decrease total income from continuing operations before unallocable income taxes by $14 million for 2014 and increase total income from continuing operations before unallocable income taxes by $613 million for 2013). The $266 million (10%) period-to-period increase in income from continuing operations before unallocable income taxes remaining, after giving effect to these certain items, reflects better overall performance primarily from our Natural Gas Pipelines, Products Pipelines and Terminals segments in 2014.

Year Ended December 31, 2013 vs. 2012

The certain items described in footnotes (b), (c) and (d) to the tables above accounted for $1,361 million increase in income from continuing operations before unallocable income taxes in 2013, when compared to 2012 (combining to increase total income from continuing operations before unallocable income taxes by $613 million for 2013 and decrease total income from continuing operations before unallocable income taxes by $748 million for 2012). The $697 million (34%) period-to-period increase in income from continuing operations before unallocable income taxes remaining, after giving effect to these certain items, reflects better overall performance from our segments in 2013 driven by our Natural Gas Pipelines segment (primarily due to a full year of contributions from the EP operations).

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Natural Gas Pipelines

	Year Ended December 31,		
	2014	2013	2012
	(In millions, except operating statistics)		
Revenues(a)(c)	$10,168	$8,617	$5,230
Operating expenses	(6,241)	(5,235)	(3,111)
Other income (expense)	(5)	24	(14)
Earnings from equity investments	318	232	52
Interest income and Other, net	25	578	22
Income tax expense	(6)	(9)	(5)
EBDA from continuing operations(b)	4,259	4,207	2,174
Discontinued operations(c)	—	(4)	(770)
Certain items(a)(b)(c)	(190)	(486)	1,139
EBDA before certain items	$4,069	$3,717	$2,543
Change from prior period	Increase/(Decrease)		
Revenues before certain items(a)	$1,339	$3,176	
EBDA before certain items	$352	$1,174	
Natural gas transport volumes (BBtu/d)(d)	32,627	30,647	31,650
Natural gas sales volumes (BBtu/d)(e)	2,334	2,458	2,402
Natural gas gathering volumes (BBtu/d)(f)	3,080	2,959	2,996

Certain item footnotes

(a) 2014 amount includes a $198 million increase in revenue and earnings associated with the early termination charge of a long-term natural gas transportation contract from a certain customer on our Kinder Morgan Louisiana pipeline system. 2014 and 2013 amounts include $2 million and $16 million decreases, respectively, related to derivative contracts used to hedge forecasted natural gas, NGL and crude oil sales.

(b) 2014 and 2013 amounts include $190 million and $490 million increases in earnings and 2012 amount includes a $202 million decrease in earnings, respectively, related to the combined effect from certain items. 2014 amount consists of (i) $198 million increase in earnings related to the early termination of a natural gas transportation contact, as described in footnote (a); (ii) $3 million loss related to sale of certain Gulf Coast offshore and onshore TGP supply facilities; and (iii) a combined $5 million decrease in earnings from other certain items. 2013 amount consists of (i) a $558 million gain from the remeasurement of a previously held 50% equity interest in Eagle Ford to fair value; (ii) a $36 million gain from the sale of certain Gulf Coast offshore and onshore TGP supply facilities; (iii) a $16 million decrease in earnings related to derivative contracts, as described in footnote (a); and (iv) a combined $23 million decrease in earnings from other certain items. 2013 and 2012 amounts include $65 million and $200 million, respectively, non-cash equity investment impairment charges related to our 20% ownership interest in NGPL Holdco LLC. 2012 amount also consists of a combined $2 million decrease in earnings from other certain items.

(c) Represents EBDA attributable to the FTC Natural Gas Pipelines disposal group. 2013 amount represents a loss from the sale of net assets. 2012 amount includes (i) a combined loss of $937 million from the remeasurement of net assets to fair value and the sale of net assets; (ii) $167 million of EBDA (which included revenues of $227 million); and (iii) $7 million of DD&A expense from discontinued operations.

Other footnotes

(d) Includes pipeline volumes for TransColorado Gas Transmission Company LLC, MEP, Kinder Morgan Louisiana Pipeline LLC, FEP, TGP, EPNG, Copano South Texas, the Texas intrastate natural gas pipeline group, CIG, WIC, CPG, SNG, Elba Express, NGPL, Citrus and Ruby Pipeline, L.L.C. Volumes for acquired pipelines are included for all periods. However, EBDA contributions from acquisitions are included only for the periods subsequent to their acquisition.

(e) Represents volumes for the Texas intrastate natural gas pipeline group.

(f) Includes Copano operations, EP midstream assets operations, KinderHawk, Endeavor, Bighorn Gas Gathering L.L.C., Webb Duval Gatherers, Fort Union Gas Gathering L.L.C., EagleHawk, and Red Cedar Gathering Company throughput volumes. Joint venture throughput is reported at our ownership share. Volumes for acquired pipelines are included for all periods.

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Following is information, including discontinued operations, related to the increases and decreases in both EBDA and revenues before certain items in 2014 and 2013, when compared with the respective prior year:

Year Ended December 31, 2014 versus Year Ended December 31, 2013

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Copano operations (including Eagle Ford)(a)	$163	n/a	$998	n/a
TGP	121	15%	151	14%
EPNG	37	10%	59	11%
Ruby(b)	18	199%	n/a	n/a
Citrus(b)	13	15%	n/a	n/a
Texas Intrastate Natural Gas Pipeline Group	11	3%	432	12%
WIC	(24)	(17)%	(26)	(15)%
SNG	(17)	(4)%	(25)	(4)%
All others (including eliminations)	30	3%	(250)	(24)%
Total Natural Gas Pipelines	$352	9%	$1,339	16%

n/a - not applicable

(a) On May 1, 2013, as part of Copano acquisition, we acquired the remaining 50% interest of Eagle Ford. Prior to that date, we recorded earnings from Eagle Ford under the equity method of accounting, but we received distributions in amounts essentially equal to equity earnings plus our share of depreciation and amortization expenses less our share of sustaining capital expenditures (those capital expenditures which do not increase the capacity or throughput).

(b) Equity investment.

The significant changes in our Natural Gas Pipelines business segment's EBDA before certain items in the comparable years of 2014 and 2013 included the following:

- increase of $163 million from full year ownership of our Copano operations, which we acquired effective May 1, 2013, including benefits from higher gathering volumes from the Eagle Ford Shale;
- increase of $121 million (15%) from TGP primarily due to higher revenues from (i) firm transportation and storage services due largely to new expansion projects placed in service in the latter part of 2013 and during 2014 and (ii) usage and interruptible transportation services due to weather-related demand relative to 2013. Partially offsetting the increase in 2014 revenues were higher operating and franchise tax expenses in 2014, and a favorable operational sales margin in 2013;
- increase of $37 million (10%) from EPNG, primarily driven by higher transportation revenues and throughput due to increased deliveries to California for storage refill and increased demand in Mexico. The increase in revenues was partially offset by higher field operation and maintenance expenses;
- increase of $18 million (199%) from Ruby due largely to higher contracted firm transportation revenues and lower interest expense;
- increase of $13 million (15%) from Citrus assets, primarily due to higher transportation revenues and reduction in property taxes;
- increase of $11 million (3%) from Texas Intrastate Natural Gas Pipeline Group (including the operations of its Kinder Morgan Tejas, Border, Kinder Morgan Texas, North Texas and Mier-Monterrey Mexico pipeline systems), due largely to higher natural gas sales and transportation margins driven by higher volumes, additional customer contracts and colder weather in the first quarter of 2014, which were offset by lower processing margin due to non-renewal of a certain contract;
- decrease of $24 million (17%) from WIC, primarily due to lower reservation revenue as a result of rate reductions pursuant to its FERC Section 5 rate settlement effective November 1, 2013 and lower rates on contract renewals; and
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decrease of $17 million (4%) from SNG, driven by lower reservation and usage revenues due to rate reductions pursuant to its rate case settlement effective September 1, 2013; partially offset by incremental revenues from increased firm transportation services and revenue related to an expansion project that was placed in service in late 2013.

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Year Ended December 31, 2013 versus Year Ended December 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
TGP	$358	81%	$440	73%
Copano operations (including Eagle Ford)(a)	289	n/a	1,538	n/a
EPNG	151	68%	217	72%
SNG	129	40%	239	67%
CIG	129	78%	165	71%
SLNG	66	82%	65	62%
WIC	54	61%	53	43%
EP midstream asset operations	46	118%	81	89%
Elba Express	43	122%	43	111%
CPG	35	75%	40	65%
Citrus(b)	32	62%	n/a	n/a
All others (including eliminations)	9	1%	522	350%
Total Natural Gas Pipelines - continuing operations	1,341	56%	3,403	65%
Discontinued operations(c)	(167)	(100)%	(227)	(100)%
Total Natural Gas Pipelines - including discontinued operations	$1,174	46%	$3,176	58%

n/a – not applicable

(a) On May 1, 2013, as part of our Copano acquisition, we acquired the remaining 50% interest of Eagle Ford. Prior to that date, we recorded earnings from Eagle Ford under the equity method of accounting, but we received distributions in amounts essentially equal to equity earnings plus our share of depreciation and amortization expenses less our share of sustaining capital expenditures (those capital expenditures which do not increase the capacity or throughput).

(b) Equity investment.

(c) Represents amounts attributable to the FTC Natural Gas Pipelines disposal group.

The significant changes in the Natural Gas Pipelines business segment’s EBDA before certain items in the comparable years of 2013 and 2012 included the following:

- incremental earnings of $1,043 million associated with full-year contributions from assets acquired from EP, which was acquired effective May 25, 2012, including earnings from TGP, EPNG, SNG, CIG, SLNG, WIC, EP midstream asset operations, Elba Express, CPG and Citrus; and
- incremental earnings of $289 million from the Copano operations, which we acquired effective May 1, 2013.

The period-to-period decreases in EBDA from discontinued operations were due to the sale of the FTC Natural Gas Pipelines disposal group effective November 1, 2012. For further information about this sale, see Note 3 “Acquisitions and Divestitures—Divestitures—FTC Natural Gas Pipelines Disposal Group—Discontinued Operations” to our consolidated financial statements.

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CO2

	Year Ended December 31,		
	2014	2013	2012
	(In millions, except operating statistics)		
Revenues(a)	$1,960	$1,857	$1,677
Operating expenses	(494)	(439)	(381)
Other (loss) income	(243)	—	7
Earnings from equity investments	25	24	25
Interest income and Other, net	—	—	(1)
Income tax expense	(8)	(7)	(5)
EBDA(b)	1,240	1,435	1,322
Certain items(a)(b)	218	(3)	4
EBDA before certain items	$1,458	$1,432	$1,326
Change from prior period	Increase/(Decrease)		
Revenues before certain items(a)	$81	$166	
EBDA before certain items	$26	$106	
Southwest Colorado CO_2 production (gross) (Bcf/d)(c)	1.3	1.2	1.2
Southwest Colorado CO_2 production (net) (Bcf/d)(c)	0.5	0.5	0.5
SACROC oil production (gross)(MBbl/d)(d)	33.2	30.7	29.0
SACROC oil production (net)(MBbl/d)(e)	27.6	25.5	24.1
Yates oil production (gross)(MBbl/d)(d)	19.5	20.4	20.8
Yates oil production (net)(MBbl/d)(e)	8.8	9.0	9.3
Katz oil production (gross)(MBbl/d)(d)	3.6	2.7	1.7
Katz oil production (net)(MBbl/d)(e)	3.0	2.2	1.4
Goldsmith Landreth oil production (gross)(MBbl/d)(d)	1.3	0.7	—
Goldsmith Landreth oil production (net)(MBbl/d)(e)	1.1	0.6	—
NGL sales volumes (net)(MBbl/d)(e)	10.1	9.9	9.5
Realized weighted-average oil price per Bbl(f)	$88.41	$92.70	$87.72
Realized weighted-average NGL price per Bbl(g)	$41.87	$46.43	$50.95

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Certain item footnotes

(a) 2014 and 2013 amounts include unrealized gains of $25 million and $3 million, and 2012 amount includes unrealized losses of $11 million, respectively, all relating to derivative contracts used to hedge forecasted crude oil sales.

(b) 2014 amount includes certain items of a $218 million decrease in earnings (consists of impairment charge of $235 million related primarily to the Katz Strawn unit, an exploration charge of $8 million related to our Wolfcamp operation and a $25 million gain discussed in footnote (a) above). 2013 amount includes a $3 million increase in earnings discussed in footnote (a) above. 2012 amount includes $4 million decrease in earnings (consists of $11 million loss discussed in footnote (a) above and $7 million gain from the sale of our ownership interest in the Claytonville oil field unit), respectively.

Other footnotes

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

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

(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.

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The CO2 business segment's primary businesses involve the production, marketing and transportation of both CO_2 and crude oil, and the production and marketing of natural gas and NGL. We refer to the segment's two primary businesses as its Oil and Gas Producing Activities and its Source and Transportation Activities for each of these two primary businesses, following is information related to the increases and decreases in both EBDA and revenues before certain items in 2014 and 2013, when compared with the respective prior year:

Year Ended December 31, 2014 versus Year Ended December 31, 2013

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Source and Transportation Activities	$56	14%	$59	13%
Oil and Gas Producing Activities	(30)	(3)%	26	2%
Intrasegment eliminations	—	—%	(4)	5%
Total CO2	$26	2%	$81	4%

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The primary increases in the source and transportation activities' EBDA and revenues before certain items in the comparable years of 2014 and 2013 included the following:

- EBDA increase of $56 million (14%) driven primarily by higher revenues (described following), partly offset by higher labor costs, power costs, property taxes and severance taxes; and
- a revenue increase of $59 million (13%) driven primarily by an increase of 8% in average CO_2 contract prices. The increase in contract prices were due primarily to two factors: (i) a change in the mix of contracts resulting in more CO_2 being delivered under higher price contracts and (ii) heavier weighting of new CO_2 contract prices to the price of crude oil. CO_2 volumes were also higher by 7% when compared to the period in 2013, primarily due to expansion projects at our Doe Canyon field placed in service in the fourth quarter of 2013.

The primary changes in the oil and gas producing activities' EBDA and revenues before certain items in the comparable years of 2014 and 2013 included the following:

- EBDA decrease of $30 million (3%) driven by higher operating expenses as a result of (i) incremental well work costs at our recently acquired Goldsmith Landreth unit; (ii) increased power costs; and (iii) higher property and severance tax expenses related to higher revenues (described following). Also contributing to lower EBDA for the comparable period was lower crude oil and NGL prices, which were offset by improved net crude oil production of 8%; and
- a $26 million (2%) increase in revenues, driven primarily by an 8% increase in crude oil sales volumes. The increase in sales volumes was due primarily to higher production at the Katz unit, incremental production from the Goldsmith Landreth unit (acquired effective June 1, 2013), and higher production at the SACROC unit (volumes presented in the results of operations table above). The increase in revenues was offset in part by a 5% decrease in the realized weighted average price per barrel of crude oil and a 10% decrease in NGL prices.

Year Ended December 31, 2013 versus Year Ended December 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing Activities	$74	8%	$144	11%
Source and Transportation Activities	32	9%	40	10%
Intrasegment Eliminations	—	—	(18)	(23)%
Total CO2	$106	8%	$166	10%

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The primary increases in the oil and gas producing activities' EBDA and revenues before certain items in the comparable years of 2013 and 2012 included the following:

- EBDA increase of $74 million (8%) was driven by (i) a $144 million (11%) increase in crude oil sales revenues, due primarily to higher average realized sales prices for U.S. crude oil and partly due to higher oil sales volumes. Our realized weighted average price per barrel of crude oil increased 6% in 2013 versus 2012. The overall increase in oil sales revenues were also favorably impacted by a 7% increase in crude oil sales volumes, due primarily to both higher

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production from the Katz and SACROC field units, and to incremental production from the Goldsmith Landreth unit, which we acquired effective June 1, 2013 (volumes presented in the results of operations table above); (ii) a $65 million (20%) increase in operating expenses resulting primarily from higher fuel and power expenses, and higher maintenance and well workover expenses, all related to both increased drilling activity in 2013 and incremental expenses associated with the Goldsmith Landreth field unit; and (iii) a $9 million decrease in natural gas plant products sales due to a 9% decrease in our realized weighted average price per barrel of NGL, partially offset by a 4% increase in sales volumes.

The primary increases in the source and transportation activities' EBDA and revenues before certain items in the comparable years of 2013 and 2012 included the following:

- EBDA increase of $32 million (9%) and revenue increase of $40 million (10%) were primarily driven by (i) higher CO_2 sales revenues, due to an almost 10% increase in average sales prices; (ii) higher reimbursable project revenues, largely related to the completion of prior expansion projects on the Central Basin pipeline system; and (iii) higher third party storage revenues at the Yates field unit.

Terminals

	Year Ended December 31,		
	2014	2013	2012
	(In millions, except operating statistics)		
Revenues(a)	$1,718	$1,410	$1,359
Operating expenses	(746)	(657)	(685)
Other (expense) income	(29)	74	14
Earnings from equity investments	18	22	21
Interest income and Other, net	12	1	2
Income tax expense	(29)	(14)	(3)
EBDA(a)	944	836	708
Certain items, net(a)	35	(38)	44
EBDA before certain items	$979	$798	$752
Change from prior period	Increase/(Decrease)		
Revenues before certain items(a)	$298	$43	
EBDA before certain items	$181	$46	
Bulk transload tonnage (MMtons)(b)	88.0	89.9	97.5
Ethanol (MMBbl)	71.8	65.0	65.3
Liquids leaseable capacity (MMBbl)	78.0	68.0	60.4
Liquids utilization %(c)	95.3%	94.6%	92.8%

Certain item footnotes

(a) 2014 amount includes (i) an $18 million increase in revenues from the amortization of deferred credits (associated with below market contracts assumed upon acquisition) from our Jones Act tankers acquired effective January 17, 2014 (APT acquisition); (ii) a $29 million write-down associated with a pending sale of certain terminals to a third-party; (iii) a $12 million increase in expenses due to hurricane clean-up and repair activities at our New York Harbor and Mid-Atlantic terminals; and (iv) a $12 million increase in expense associated with a liability adjustment related to a certain litigation matter. 2013 amount includes (i) a $109 million increase in earnings from casualty indemnification gains; (ii) a $59 million increase in clean-up and repair expense, all related to 2012 hurricane activity at the New York Harbor and Mid-Atlantic terminals; and (iii) a combined $12 million decrease of earnings from other certain items (which includes a $8 million increase in revenues related to hurricane reimbursements). 2012 amount includes a $51 million increase in expense related to hurricanes Sandy and Isaac clean-up and repair activities and the associated write-off of damaged assets, a $12 million casualty indemnification gain related to a 2010 casualty at the Myrtle Grove, Louisiana, International Marine Terminal facility and a combined $5 million decrease of earnings from other certain items.

Other footnotes

(b) Volumes for acquired terminals are included for all periods and include our proportionate share of joint venture tonnage.

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

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The Terminals business segment includes the transportation, transloading and storing of petroleum products, crude oil, condensate (other than those included in the Products Pipelines segment), and bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals. The bulk and liquids terminal operations are grouped into regions based on geographic location and/or primary operating function. This structure allows the management to organize and evaluate segment performance and to help make operating decisions and allocate resources.

Following is information related to the increases and decreases in both EBDA and revenues before certain items in 2014 and 2013, when compared with the respective prior year:

Year Ended December 31, 2014 versus Year Ended December 31, 2013

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Acquired assets and businesses	$66	n/a	$109	n/a
West	32	45%	49	38%
Gulf Central	30	213%	51	663%
Gulf Liquids	20	10%	22	8%
Gulf Bulk	19	25%	26	19%
All others (including intrasegment eliminations and unallocated income tax expenses)	14	3%	41	5%
Total Terminals	$181	23%	$298	21%

The primary changes in the Terminals business segment's EBDA before certain items in the comparable years of 2014 and 2013 included the following:

- increase of $66 million from acquired assets and businesses, primarily the acquisition of the Jones Act tankers;
- increase of $32 million (45%) from our West region terminals, driven by the completion of Edmonton expansion projects;
- increase of $30 million (213%) from our Gulf Central terminals, driven by higher earnings from our 55% owned Battleground Oil Specialty Terminal Company LLC (BOSTCO) oil terminal joint venture, which is located on the Houston Ship Channel and began operations in October 2013;
- increase of $20 million (10%) from our Gulf Liquids terminals, due to higher liquids warehousing revenues from our Pasadena and Galena Park liquids facilities located along the Houston Ship Channel. The facilities benefited from high gasoline export demand, increased rail services and new and incremental customer agreements at higher rates, due in part to new tankage from completed expansion projects;
- increase of $19 million (25%) from our Gulf Bulk terminals, driven by increased revenue from take-or-pay coal contracts and higher petcoke period-to-period volumes in 2014, due largely to refinery and coker shutdowns in 2013 as a result of turnarounds taken; and
- increase of $14 million (3%) from the rest of the terminal operations was driven primarily by increased shortfall revenue recognized on take-or-pay contracts at out International Marine Terminal in Myrtle Grove, Louisiana and earnings from the BP Whiting terminal in Whiting, Indiana which was placed in service in the third quarter of 2013.

Year Ended December 31, 2013 versus Year Ended December 31, 20

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Gulf Liquids	$21	11%	$34	14%
Rivers	15	24%	7	5%
Midwest	9	18%	14	11%

All others (including intrasegment eliminations and unallocated income tax expenses)	1	—%	(12	) 1%
Total Terminals	$46	6%	$43	3%

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The primary changes in the Terminals business segment's EBDA before certain items in the comparable years of 2013 and 2012 included the following:

- increase of $21 million (11%) from our Gulf Liquids terminals, primarily due to higher liquids revenues from our Pasadena and Galena Park liquids facilities located along the Houston Ship Channel. The facilities benefited from high gasoline export demand, increased rail services, and new and incremental customer agreements at higher rates. For all terminals included in the Terminals business segment, total liquids leaseable capacity increased to 68.0 MMBbl at year-end 2013, up 12.6% from a capacity of 60.4 MMBbl at the end of 2012. The increase in capacity was mainly due to the acquisition of Norfolk and Chesapeake, Virginia facilities from Allied Terminals in June 2013 (incremental contributions from these two terminals are included within the "All others" line in the table above), and the partial in-service of BOSTCO and Edmonton Tank expansion projects. At the same time, Terminals' overall liquids utilization rate increased 1.8% since the end of 2012;
- increase of $15 million (24%) from our Rivers region terminals due to the IMT Phase I and II expansion projects at International Marine Terminal (located at Myrtle Grove, Louisiana, near the mouth of the Mississippi River) being placed in service in March 2013. The region also benefited from lower operating and maintenance costs; and
- increase of $9 million (18%) from our Midwest region terminals, primarily driven by the opening of the BP Whiting terminal (Whiting Indiana) in August 2013. Salt and ethanol volumes increases also contributed to the overall improvement.

Products Pipelines

	Year Ended December 31,		
	2014	2013	2012
	(In millions, except operating statistics)		
Revenues	$2,068	$1,853	$1,370
Operating expenses	(1,258)	(1,295)	(759)
Other income (expense)	3	(6)	5
Earnings from equity investments	44	45	39
Interest income and Other, net	1	3	11
Income tax (expense) benefit	(2)	2	2
EBDA(a)	856	602	668
Certain items, net(a)	4	182	35
EBDA before certain items	$860	$784	$703
Change from prior period	Increase/(Decrease)		
Revenues	$215	$483	
EBDA before certain items	$76	$81	
Gasoline (MMBbl) (b)	451.8	423.4	395.3
Diesel fuel (MMBbl)	151.5	142.4	141.5
Jet fuel (MMBbl)	113.3	110.6	110.6
Total refined product volumes (MMBbl)(c)	716.6	676.4	647.4
NGL (MMBbl)(d)	35.2	37.3	31.7
Condensate (MMBbl)(e)	36.8	12.6	1.4
Total delivery volumes (MMBbl)	788.6	726.3	680.5
Ethanol (MMBbl)(f)	41.6	38.7	33.1

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Certain item footnote

(a) 2014 amount includes a $4 million increase in expense associated with a certain Pacific operations litigation matter. 2013 amount includes (i) a $162 million increase in expense associated with rate case liability adjustments;

(ii) a $15 million increase in expense associated with a legal liability adjustment related to a certain West Coast terminal environmental matter; and (iii) $5 million loss from the write-off of assets at our Los Angeles Harbor West Coast terminal. 2012 amount includes a $32 million increase in expense associated with environmental liability and environmental recoverable receivable adjustments and a combined $3 million decrease in earnings from other certain items.

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Other footnotes
(b) Volumes include ethanol pipeline volumes.
(c) Includes Pacific, Plantation Pipe Line Company, Calnev, Central Florida and Parkway pipeline volumes.
(d) Includes Cochin and Cypress pipeline volumes.
(e) Includes Kinder Morgan Crude & Condensate and Double Eagle Pipeline LLC pipeline volumes.
(f) Represents total ethanol volumes, including ethanol pipeline volumes included in gasoline volumes above.

Following is information related to the increases and decreases in both EBDA and revenues before certain items in 2014 and 2013, when compared with the respective prior year:

Year Ended December 31, 2014 versus Year Ended December 31, 2013

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Crude & Condensate Pipeline	$67	320%	$89	402%
Pacific operations	36	13%	25	6%
Transmix operations	(19)	(44)%	92	10%
All others (including eliminations)	(8)	(2)%	9	2%
Total Products Pipelines	$76	10%	$215	12%

The primary changes in the Products Pipelines business segment's EBDA before certain items in the comparable years of 2014 and 2013 included the following:

- increase of $67 million (320%) from Kinder Morgan Crude & Condensate Pipeline, driven primarily by an increase of pipeline throughput volumes to 81.0 MBbl/d as compared to 24.1 MBbl/d in 2013 (236%);
- increase of $36 million (13%) from our Pacific operations, due to higher service revenues driven by higher volumes and margins and lower operating expenses primarily due to lower rights-of-way expenses; and
- decrease of $19 million (44%) from our transmix processing operations, primarily driven by unfavorable inventory pricing.

Year Ended December 31, 2013 versus Year Ended December 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Transmix operations	$27	174%	$406	82%
Cochin Pipeline	25	34%	33	42%
Crude & Condensate Pipeline	14	n/a	19	n/a
All others (including eliminations)	15	2%	25	3%
Total Products Pipelines	$81	12%	$483	35%

n/a - not applicable

The primary changes in the Products Pipelines business segment's EBDA before certain items in 2013 compared to 2012 were attributable to the following:

- a $27 million (174%) increase from our transmix processing operations due to higher margins on processing volumes, incremental earnings from third-party sales of excess renewable identification numbers (RINS) (generated through its ethanol blending operations), and the recognition of unfavorable net carrying value adjustments to product inventory recognized in 2012. The period-to-period increases in revenues were mainly due to the expiration of certain transmix fee-based processing agreements since the end of the third quarter of 2012. Due to the expiration of these contracts, we now directly purchase incremental transmix volumes and sell incremental volumes of refined products, resulting in both higher revenues and higher costs of sales expenses;

- a $25 million (34%) increase from Cochin Pipeline primarily due to higher transportation revenues, driven by an overall 33% increase in pipeline throughput volumes, partly attributable to incremental ethane/propane volumes as a result of pipeline modification projects completed in June 2012;

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- incremental earnings of $14 million from Kinder Morgan Crude & Condensate Pipeline, which began transporting crude oil and condensate volumes from the Eagle Ford shale gas formation to multiple terminaling facilities along the Texas Gulf Coast in October 2012; and
- a $15 million (2%) increase from all other represents a number of small increases at various locations.

Kinder Morgan Canada

	Year Ended December 31,		
	2014	2013	2012
	(In millions, except operating statistics)		
Revenues	$291	$302	$311
Operating expenses	(106)	(110)	(103)
Earnings from equity investments	—	4	5
Interest income and Other, net	15	249	17
Income tax expense	(18)	(21)	(1)
EBDA(a)	182	424	229
Certain items, net(a)	—	(224)	—
EBDA before certain items	$182	$200	$229
Change from prior period	Increase/(Decrease)		
Revenues	$(11)	$(9)	
EBDA before certain items	$(18)	$(29)	
Transport volumes (MMBbl)(b)	106.8	101.1	106.1

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Certain item footnote

(a) 2013 amount includes a $224 million pre-tax gain from the sale of our equity and debt investments in the Express pipeline system.

Other footnote

(b) Represents Trans Mountain pipeline system volumes.

The Kinder Morgan Canada business segment includes the operations of the Trans Mountain and Jet Fuel pipeline systems and until March 14, 2013, the effective date of sale, our one-third ownership interest in the Express crude oil pipeline system.

Following is information related to increases and decreases in both EBDA and revenues before certain items in 2014 and 2013, when compared with the respective prior year:

Year Ended December 31, 2014 versus Year Ended December 31, 2013

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Express Pipeline(a)	$(6)	(44)%	n/a	n/a
Trans Mountain Pipeline	(12)	(6)%	$(11)	(4)%
Total Kinder Morgan Canada	$(18)	(9)%	$(11)	(4)%

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n/a - not applicable

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

For the comparable years of 2014 and 2013, the Trans Mountain Pipeline had a decrease in earnings of $12 million (6%) which was driven primarily by an unfavorable impact from foreign currency translation. Due to the weakening of the Canadian dollar since the end of the third quarter of 2013, we translated Canadian denominated income and expense amounts into fewer U.S. dollars in 2014.

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Year Ended December 31, 2013 versus Year Ended December 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	$(24)	(11)%	$(9)	(3)%
Express Pipeline(a)	(5)	(28)%	n/a	n/a
Total Kinder Morgan Canada	$(29)	(13)%	$(9)	(3)%

n/a - not applicable

(a) We sold our debt and equity investments in Express Pipeline on March 14, 2013. Prior to the sale, the earnings from Express Pipeline were recorded under the equity method of accounting.

The period-to-period decreases in EBDA from Express were primarily due to both lower equity earnings and lower interest income resulting from the sale of our equity and debt investments in Express effective March 14, 2013.

The decreases in Trans Mountain's earnings were driven by (i) higher income tax expenses (due largely to general increases in British Columbia's income tax rates since the end of the third quarter of 2012); (ii) unfavorable impacts from foreign currency translation (due to the weakening of the Canadian dollar since the end of 2012, we translated Canadian denominated income and expense amounts into less U.S. dollars in 2013); and (iii) lower management incentive fees earned from the operation of the Express pipeline system (due to its sale in March 2013). The period-to-period decreases in Trans Mountain's earnings were partially offset by incremental non-operating income from allowances for funds used during construction (representing an estimate of the cost of capital funded by equity contributions).

Other

Our other segment results are driven by activities from other miscellaneous assets and liabilities purchased in our 2012 EP acquisition that were not allocated to the above segments. This segment contributed earnings of $13 million, a loss of $5 million and earnings of $7 million for the years ended 2014, 2013 and 2012, respectively. However, 2014 and 2012 earnings include a certain item of $22 million increase in earnings and $10 million decrease in earnings, respectively, primarily related to our foreign operations. After taking into effect the certain item, the earnings for 2014 and 2013 decreased by $4 million and $22 million, respectively, when compared with the respective prior year.

General and Administrative, Interest, and Noncontrolling Interests

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
General and administrative expense(a)(c)	$610	$613	$929
Certain items(a)	28	8	(366)
Management fee reimbursement(c)	(36)	(36)	(35)
General and administrative expense before certain items	$602	$585	$528
Unallocable interest expense net of interest income and other, net(b)	$1,807	$1,688	$1,441
Certain items(b)	3	32	(87)
Unallocable interest expense net of interest income and other, net, before certain items	$1,810	$1,720	$1,354
Net income attributable to noncontrolling interests	$1,417	$1,499	$112

Certain item footnotes

(a)

2014 amount includes a decrease in expense of $39 million related to pension credit income and a net increase of $11 million in expense for various other certain items. 2013 amount includes a decrease in expense of $59 million related to EP post-merger pension credits, partially offset by increases in expense of (i) $41 million related to asset and business acquisition costs and unallocated legal expenses and (ii) combined $10 million from other certain items primarily related to the EP acquisition. 2012 amount includes $366 million increase of pre-tax expense associated with the EP acquisition and EP Energy sale, which includes (i) $160 million in employee severance, retention and bonus costs; (ii) $87 million of accelerated EP stock based compensation allocated to the post-combination period under applicable GAAP rules; (iii) $37 million in advisory fees; (iv) $68 million for legal fees and reserves, net of recoveries;

(v) $29 million of other EP acquisition expenses; and (vi) a combined $14 million increase in expense from other certain items; partially offset by a $29 million benefit associated with pension income.

(b) 2014, 2013 and 2012 amounts include $9 million, $21 million and $108 million of amortization of capitalized financing fees, almost all of which was associated with the EP acquisition financing. 2012 also includes amounts written-off due to debt repayment. 2014, 2013 and 2012 amounts include (i) $12 million, $14 million and $9 million, respectively, of interest expense on margin for marketing contracts and (ii) $65 million, $67 million and $29 million, respectively, of decreased interest expense related to debt fair value adjustments associated with the EP and Copano acquisitions. 2014 amount includes (i) $27 million of interest expense related to the Merger Transactions; and (ii) an increase in interest expense of $15 million associated with a certain Pacific operations litigation matter. 2014 and 2012 also include $1 million and $1 million decreases in expense, respectively, related to the combined effect from other certain items.

Other footnote

(c) 2014, 2013 and 2012 amounts include NGPL Holdco LLC general and administrative reimbursements of $36 million, $36 million and $35 million, respectively. These amounts were recorded to the "Product sales and other" caption in our accompanying consolidated statements of income with the offsetting expenses primarily included in the "General and administrative" expense caption in our accompanying consolidated statements of income.

Items not attributable to any segment include general and administrative expenses, unallocable interest income and income tax expense, interest expense, and net income attributable to noncontrolling interests. Our general and administrative expenses include such items as unallocated salaries and employee-related expenses, employee benefits, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services including accounting, information technology, human resources and legal services. These expenses are generally not controllable by our business segment operating managers and therefore are not included when we measure business segment operating performance. For this reason, we do not specifically allocate our general and administrative expenses to the business segments. As discussed previously, we use segment EBDA internally as a measure of profit and loss to evaluate segment performance, and each of our segment's EBDA includes all costs directly incurred by that segment.

The increase in general and administrative expenses before certain items of $17 million and $57 million in 2014 and 2013 when compared with the respective prior year was primarily driven by the acquisition of Copano (effective May 1, 2013) and EP (effective May 25, 2012). Additional drivers were higher benefit costs, payroll taxes and segment labor expenses partially offset by lower costs on our corporate headquarters building and insurance costs.

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, increased $90 million and $366 million in 2014 and 2013, respectively, when compared with the respective prior year. The increase in interest expense in 2014 as compared to 2013 was primarily due to higher average debt balances as a result of capital expenditures, joint venture contributions and acquisitions that were made during 2014 and issuing $6 billion of debt primarily related to the Merger Transactions in November 2014. In addition, the increase was impacted by the refinancing of the short-term KMI credit facility debt with a $1.5 billion long-term debt issuance in November 2013, which had a higher interest rate. This increase in interest expense was partially offset by (i) lower average balances outstanding on our EP acquisition term loan as a result of its termination in November 2014 and (ii) lower interest rates on our credit facility and EP acquisition term loan as a result of the refinancing of these facilities in 2014.

The increase in interest expense in 2013 as compared to respective prior year was primarily due to interest expense incurred from EP acquisition debt, debt assumed in the EP acquisition, and other business acquisitions, see Notes 3 "Acquisition and Divestitures" and Note 8 "Debt" to our consolidated financial statements. Also contributed to the increase in 2013 as compared to 2012 were higher effective interest rates and higher average borrowings which were largely due to the capital expenditures and joint venture contributions. For more information on the capital expenditures and capital contributions see "—Liquidity and Capital Resources."

We use interest rate swap agreements to transform a portion of the underlying cash flows related to our long-term fixed rate debt securities (senior notes) into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. As of December 31, 2014, approximately 26% 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. As of December 31, 2013, approximately 25% of our debt balances (excluding debt fair value adjustments) were subject to variable interest rates. For more information on our interest rate swaps, see Note 13 "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 held by us. The $82 million decrease (5%) for 2014 as compared to 2013 was primarily due to our noncontrolling interests' portion of (i) our 2013 $558 million pre-tax gain from the remeasurement of our previously held 50% equity interest in Eagle Ford to fair value; and (ii) our 2013 $140 million after-tax gain on the sale of our investments in the Express pipeline system; which was partially offset by our noncontrolling interests' portion of our 2014 $198 million pre-tax increase associated with the early termination of a long-term natural gas transportation contract on our Kinder Morgan Louisiana pipeline system and an increase in income allocated to noncontolling interests during the fourth quarter 2014 due to the elimination of the incentive distribution rights as a result of the Merger Transactions. The $1,387 million (1,238%) increase for 2013 as compared to 2012 was primarily due to our noncontrolling interests' portion of (i) our 2013 $558 million gain from the remeasurement of our previously held 50% equity interest in Eagle Ford to fair value; (ii) our 2013 $140 million after-tax gain on the sale of our investments in the Express pipeline system; (iii) additional income from EP assets acquired in 2012; (iv) additional income from our 2013 acquisition of Copano; and (v) the 2012 non-cash loss of $937 million net of tax loss from both costs to sell and the remeasurement of FTC Natural Gas Pipeline disposal group net assets to fair value.

Subsequent to the Merger Transactions, net income attributable to noncontrolling interests represents net income allocated to third-party ownership interests in consolidated subsidiaries. Prior to the Merger Transactions it also included net income allocated to KMP and EPB limited partner units formerly owned by the public.

Income Taxes—Continuing Operations

Year Ended December 31, 2014 versus Year Ended December 31, 2013

Our tax expense for income from continuing operations for the year ended December 31, 2014 was $648 million, as compared with 2013 income tax expense of $742 million. The $94 million decrease in tax expense is due primarily to (i) the tax impact of significantly lower pretax earnings in 2014 associated with our investment in KMP (primarily as a result of KMP's 2014 recognition of a $235 million impairment of its CO_2 assets compared to gains it recognized in 2013 of $558 million on remeasurement to fair value of its initial 50% interest in the Eagle Ford joint venture and $224 million on the sale of its one-third interest in the Express pipeline system); (ii) a 2014 worthless stock deduction related to our Brazil operations; and (iii) a 2013 decrease in our share of non tax-deductible goodwill associated with our investment in KMP (as a result of our change in ownership primarily due to KMP's acquisition of Copano). These decreases are partially offset by (i) the tax benefit in 2013 of a decrease in the deferred state tax rate as a result of the drop-down of our 50% ownership interest in EPNG and midstream assets and KMP's acquisition of Copano; (ii) 2013 adjustments to our income tax reserve for uncertain tax positions as a result of the settlement of legacy EP Internal Revenue Service audits; and (iii) the 2014 recording of a valuation allowance related to our investment in NGPL.

Year Ended December 31, 2013 versus Year Ended December 31, 2012

Our tax expense for income from continuing operations for the year ended December 31, 2013 was $742 million, as compared with 2012 income tax expense of $139 million. The $603 million increase in tax expense is due primarily to (i) higher income in 2013 attributable to our investments in KMP and EPB as compared to 2012 and (ii) tax expense as a result of KMP's 2013 sale of its one-third interest in the Express pipeline system. These increases are partially offset by a decrease in the deferred state tax rate as a result of the March 2013 drop-down transaction and KMP's Copano acquisition.

Liquidity and Capital Resources

General

As of December 31, 2014, we had a combined $315 million of "Cash and cash equivalents," on our consolidated balance sheet, a decrease of $283 million (47%) from December 31, 2013. We believe our cash position and remaining borrowing capacity (discussed below in “—Short-term Liquidity”), and our access to financial resources are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations.

Our primary cash requirements, in addition to normal operating expenses, are for debt service, sustaining capital expenditures, expansion capital expenditures and quarterly dividends to our common shareholders.

In general, we expect to fund:

- cash dividends and sustaining capital expenditures with existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits with retained cash, proceeds from divestitures, additional borrowings (including commercial paper issuances), and the issuance of additional common stock;
- interest payments with cash flows from operating activities; and

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- debt principal payments, as such debt principal payments become due, with proceeds from divestitures, additional borrowings or by the issuance of additional common stock.

In addition to our results of operations, our debt and capital balances are affected by our financing activities, as discussed below in "—Financing Activities." Cash provided from our operations is fairly stable across periods since a majority of our cash generated is fee based from a diversified portfolio of assets and is not sensitive to commodity prices. However, in our CO_2 business segment, while we hedge the majority of our oil production, we do have exposure to unhedged volumes, a significant portion of which are NGL.
Historically, our distributions to noncontrolling interests were primarily comprised of distributions made by KMP and EPB on their common units that were not owned by us. With the closing of the Merger Transactions, all the previously held equity securities of KMP, EPB and KMR are now owned by us. As partial consideration for the KMP, EPB and KMR equity securities that we did not already own as of the Merger Transactions date, we issued approximately 1,097 million KMI Class P common shares. We expect that dividends on KMI's Class P common stock will be $2.00 per share for 2015. Also, see "—KMI Dividends."

Credit Ratings and Capital Market Liquidity

Based on our historical record, we believe that our capital structure will continue to allow us to achieve our business objectives. We expect that our short-term liquidity needs will be met primarily through short-term borrowings. We are subject, however, to conditions in the equity and debt markets and there can be no assurance we will be able or willing to access the public or private markets for equity and/or long-term senior notes in the future. If we were unable or unwilling to access the capital markets, we would be required to either restrict expansion capital expenditures and/or potential future acquisitions or pursue debt financing alternatives, some of which could involve higher costs or negatively affect our and/or our subsidiaries' credit ratings.

Our short-term corporate debt rating is A-3, Prime-3 and F3 at Standard and Poor's, Moody's Investor Services and Fitch Ratings, Inc., respectively.

The following table represents KMI's and KMP's senior unsecured debt ratings as of December 31, 2014.

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

Short-term Liquidity

As of December 31, 2014 our principal sources of short-term liquidity are (i) our $4.0 billion revolving credit facility and associated $4.0 billion commercial paper program (discussed following); and (ii) cash from operations. The loan commitments under our revolving credit facility can be used to fund borrowings for working capital and other general corporate purposes and also serve as a backup for our commercial paper program. We provide for liquidity by maintaining a sizable amount of excess borrowing capacity under our credit facility and have consistently generated strong cash flow from operations, providing a source of funds of $4,467 million and $4,122 million in 2014 and 2013, respectively (the year-to-year increase is discussed below in "Cash Flows—Operating Activities").

Effective upon the closing of the Merger Transactions on November 26, 2014, we replaced the prior KMI credit agreement, the KMP credit agreement and the EPB credit agreement with a 5-year, $4 billion revolving credit facility with a syndicate of lenders, which can be increased to $5 billion if certain circumstances are met. On November 26, 2014, we entered into a $4.0 billion commercial paper program. Borrowings under our commercial paper program and letters of credit reduce borrowings allowed under our credit facility. For additional information on our credit facility and commercial paper program, see Note 8 “Debt” to our consolidated financial statements.

In connection with the Hiland acquisition, we entered into and made borrowings of $1,641 million under a new six-month bridge credit facility with UBS AG, Stamford Branch. The credit facility bears interest at the same rate as our $4.0 billion revolving credit facility and the borrowing capacity is reduced by any payments made. As of the date of this filing, we had $1,516 million outstanding under this credit facility.

Our short-term debt as of December 31, 2014 was $2,717 million, primarily consisting of (i) $1,236 million combined outstanding borrowings under our $4 billion credit facility and $4 billion commercial paper program; (ii) $375 million in principal amount of 4.10% senior notes that mature November 15, 2015; (iii) $340 million in principal amount of 6.80% senior notes that mature November 15, 2015; (iv) $300 million in principal amount of 5.625% senior notes that mature February 15, 2015; and (v) $250 million in principal amount of 5.15% senior notes that mature March 1, 2015. We intend to refinance our short-term debt through additional credit facility borrowings, commercial paper borrowings, issuing new long-term debt, or with proceeds from asset sales. Our combined balance of short-term debt as of December 31, 2013 was $2,306 million.

We had working capital (defined as current assets less current liabilities) deficits of $2,610 million and $2,207 million as of December 31, 2014 and 2013, respectively. Our current liabilities include short-term borrowings used to finance our expansion capital expenditures which are periodically replaced with long-term financing. The overall $403 million (18%) unfavorable change from year-end 2013 was primarily due to (i) a net increase in KMI's credit facility and commercial paper borrowings; (ii) lower cash balances (described above); and (iii) an increase in the current portion of long-term debt. The overall increase in our working capital deficit was partially offset by the repayment of KMP's commercial paper borrowings and the subsequent termination of the program. 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 combined cash and cash equivalent balances as a result of our equity issuances and our or our subsidiaries' debt issuances (discussed below in "—Long-term Financing" and "— Capital Expenditures").

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

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

Long-term Financing

In addition to our principal sources of short-term liquidity listed above, we could meet our cash requirements through the issuance of long-term securities or additional common shares. Our equity offerings consist of the issuance of additional Class P common stock with a par value of $0.01 per share. Through an equity distribution agreement, we can issue and sell through or to our sales agents and/or principals shares of our Class P common stock from time to time up to an aggregate offering price of $5 billion. For more information on our equity issuances during 2014 and our equity distribution agreement, see Note 10, "Stockholders' Equity" to our consolidated financial statements.

From time to time, we issue long-term debt securities, often referred to as senior notes. All of our senior notes issued to date, other than those issued by certain of our subsidiaries, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. All of our fixed rate senior notes provide that the notes may be redeemed at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date, and, in most cases, plus a make-whole premium. As of December 31, 2014 and 2013, the aggregate principal amount outstanding of the various series of KMI's senior notes (excluding our subsidiaries' senior borrowings discussed below) was $11,438 million (including $6 billion issued in 2014 to fund the cash portion of consideration of the Merger Transactions), and $5,645 million, respectively.

In addition, from time to time our subsidiaries, including KMP, TGP, EPNG, CIG, SNG and Copano, have issued long-term debt securities, often referred to as their senior notes. Most of the debt of our subsidiaries is unsecured; however a modest amount of secured debt has been incurred by our subsidiaries. As of December 31, 2014 and 2013, the total liability balance due on the various borrowings of our subsidiaries (including senior notes issued by KMP, TGP, EPNG, CIG, SNG and Copano) was $28,355 million and $25,889 million, respectively.

Furthermore, we and almost all of our direct and indirect wholly-owned domestic subsidiaries, are parties to a cross guaranty wherein we each guarantee the debt of each other. See Note 18 “Guarantee of Securities of Subsidiaries” to our consolidated financial statements.

To date, our and our subsidiaries’ debt balances have not adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. For additional information about our debt-related transactions in 2014, see Note 8 “Debt” to our consolidated financial statements. For information about our interest rate risk, see Item 7A “Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk.”

Capital Structure

We finance our expansion capital expenditures and acquisitions with a combination of equity and debt in order to maintain an approximate net debt to EBITDA ratio between 5.0 and 5.5. In the short-term, we may fund these expenditures from borrowings under our credit facility until the amount borrowed is of a sufficient size to cost effectively offer either debt, equity, or both.

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

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 “—KMI Dividends.”

Our capital expenditures for the year ended December 31, 2014, and the amount we expect to spend for 2015 to sustain and grow our business are as follows (in millions):

	2014	Expected 2015
Sustaining capital expenditures(a)	$509	$586
Discretionary capital expenditures(b)(c)	$3,580	$4,381

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(a) 2014 and Expected 2015 amounts include $57 million and $82 million, respectively, for our proportionate share of sustaining capital expenditures of certain unconsolidated joint ventures.

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(b) 2014 amount (i) includes $533 million of discretionary capital expenditures of unconsolidated joint ventures and acquisitions and (ii) excludes a combined $118 million net change from accrued capital expenditures, contractor retainage and amounts primarily related to contributions from noncontrolling interests to fund a portion of certain capital projects

(c) Expected 2015 includes our contributions to certain unconsolidated joint ventures and small acquisitions, net of contributions estimated from unaffiliated joint venture partners for consolidated investments.

Off Balance Sheet Arrangements

We have invested in entities that are not consolidated in our financial statements. For information on our obligations with respect to these investments, as well as our obligations with respect to related letters of credit, see Note 12 "Commitments and Contingent Liabilities" to our consolidated financial statements. Additional information regarding the nature and business purpose of our investments is included in Note 6 "Investments" to our consolidated financial statements.

Contractual Obligations and Commercial Commitments

	Payments due by period				
	Total	Less than 1 year	2-3 years	4-5 years	More than 5 years
	(In millions)				
Contractual obligations:					
Debt borrowings-principal payments	$41,029	$2,717	$4,743	$5,147	$28,422
Interest payments(a)	29,438	2,203	4,077	3,512	19,646
Leases and rights-of-way obligations(b)	678	97	160	132	289
Pension and postretirement welfare plans(c)	862	75	47	48	692
Transportation, volume and storage agreements(d)	1,189	162	277	249	501
Other obligations(e)	402	153	112	25	112
Total	$73,598	$5,407	$9,416	$9,113	$49,662
Other commercial commitments:					
Standby letters of credit(f)	$381	$350	$31	$—	$—
Capital expenditures(g)	$1,026	$1,026	$—	$—	$—

(a) Interest payment obligations exclude adjustments for interest rate swap agreements and assume no change in variable interest rates from those in effect at December 31, 2014.

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

(c) Represents the amount by which the benefit obligations exceeded the fair value of fund assets for pension and other postretirement benefit plans at year-end. The payments by period include expected contributions to funded plans in 2015 and estimated benefit payments for unfunded plans in all years.

(d) Primarily represents transportation agreements of $305 million, volume agreements of $498 million and storage agreements for capacity on third party and an affiliate pipeline systems of $257 million.

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

(f) The $381 million in letters of credit outstanding as of December 31, 2014 consisted of the following (i) $20 million under four letters of credit related to power and marketing purposes; (ii) $86 million under fourteen letters of credit for insurance purposes; (iii) a $100 million letter of credit that supports certain proceedings with the CPUC involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (iv) our $30 million guarantee under letters of credit totaling $46 million supporting our International Marine Terminals Partnership Plaquemines, Louisiana Port, Harbor, and Terminal Revenue Bonds; (v) a $34 million letter of credit supporting our pipeline and terminal operations in Canada; (vi) a $25 million letter of credit supporting our Kinder Morgan Liquids Terminals LLC New Jersey Economic Development Revenue Bonds; (vii) a $24 million letter of credit supporting our Kinder Morgan Operating L.P. "B" tax-exempt bonds; (viii) a $13 million letter of credit supporting Nassau County, Florida Ocean Highway and Port Authority tax-exempt bonds; and (ix) a combined $33 million in twenty-four letters of credit supporting environmental and other obligations of us and our subsidiaries.

(g) Represents commitments for the purchase of plant, property and equipment as of December 31, 2014.

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Cash Flows

Operating Activities

The net increase of $345 (8%) million in cash provided by operating activities in 2014 compared to 2013 was primarily attributable to:

- a $984 million increase in cash from overall higher net income after adjusting our period-to-period $249 million decrease in net income for non-cash items primarily consisting of the following: (i) 2013 gain on the remeasurement of our previous 50% equity investment in Eagle Ford; (ii) 2013 gain on sale of our investments in the Express pipeline system (see the discussion of these investments in Note 3 "Acquisitions and Divestitures" to our consolidated financial statements); (iii) 2014 loss on impairments on both our CO_2 and terminal long-lived assets; (iv) DD&A expenses (including amortization of excess cost of equity investments); (v) deferred income tax expenses; (vi) gains from the sale or casualty of property, plant and equipment (see discussion above in "—Results of Operations"); (vii) the net activity of our equity method investees; and (viii) adjustments to accrued transportation rate case and legal liabilities;
- a $315 million decrease in cash associated with rate case reserve payments primarily driven by the 2014 CPUC settlement and refund payments;
- a $228 million decrease in cash associated with net changes in working capital items and non-current assets and liabilities. The decrease was primarily driven by a $195 million use of cash for income tax payments made during the first three quarters of 2014 (due to discrete events in the fourth quarter, we received a refund for these payments in the first quarter of 2015); lower cash flows from both natural gas storage and pipeline transportation system balancing, and lower net dock premiums and toll collections received from our Trans Mountain pipeline system customers. These decreases were partially offset by, among other things, higher cash inflows from favorable changes in the collection and payment of trade and related party receivables and payables (due primarily to the timing of invoices received from customers and paid to vendors and suppliers), and favorable changes in previously deferred reimbursable costs; and
- a $96 million decrease in cash from interest rate swap termination payments received. In 2013, we terminated, in three separate transactions, three existing fixed-to-variable interest rate swap agreements prior to their contractual maturity dates.

Investing Activities

The $2,088 million net increase in cash used in investing activities in 2014 compared to 2013 was primarily attributable to:

- a $1,096 million decrease in cash due to higher expenditures for acquisitions. The increase in acquisition expenditures was primarily related to the $1,231 million we paid in 2014 for our APT and Crowley tanker acquisitions, versus the $280 million we paid in 2013 to acquire the Goldsmith Landreth San Andres oil field unit (both discussed in Note 3 "Acquisitions and Divestitures");
- a combined $490 million decrease in cash due to proceeds received in 2013 from divestitures, primarily consisting of our sale of the investments in the Express pipeline system;
- a $248 million decrease in cash due to higher capital expenditures in 2014 primarily reflecting higher investment undertaken to expand and improve our Products Pipelines and CO_2 business segments; and
- a $172 million decrease in cash due to higher capital contributions, driven by a $175 million contribution we made in 2014 to MEP, our 50%-owned joint venture, to fund our share of the joint venture's repayment of $350 million of senior notes that matured on September 15, 2014.

Financing Activities

The net increase of $1,566 million in cash from financing activities in 2014 compared to 2013 was primarily attributable to:

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a $5,533 million net increase in cash from overall debt financing activities. The increase was driven by, among other things, a $5,259 million increase in cash due to the issuance of our senior notes, including proceeds of $5,987 million received in 2014 from the series of senior notes we issued to fund our Merger Transactions, and a net increase of $583 million in cash from both our commercial paper and revolving credit facilities programs (reflecting an increase in issuances of $5,733 million, partially offset by an increase in payments of $5,150 million). Further information regarding the debt related to our Merger Transactions is discussed in Note 8 “Debt” to our consolidated financial statements;

- a $445 million increase in cash due to lower combined repurchases of shares and warrants;
- a $3,937 million decrease in cash resulting from the cash portion of consideration for the Merger Transactions;

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- a $321 million decrease in cash associated with distributions to noncontrolling interests, primarily reflecting increased distributions to common unit owners of KMP and EPB prior to the Merger Transactions offset by no distribution being paid for the fourth quarter of 2014 since the closing date of the Merger Transactions occurred prior to KMP or EPB declaring any additional distributions; and
- a $138 million decrease in cash due to higher dividend payments.

KMI Dividends

The table below reflects the payment of cash dividends of $1.74 per common share for 2014, a 9% increase over our 2013 dividends of $1.60 per common share.

Three months ended	Total quarterly dividend per share for the period	Date of declaration	Date of record	Date of dividend
March 31, 2014	$ 0.42	April 16, 2014	April 30, 2014	May 16, 2014
June 30, 2014	$ 0.43	July 16, 2014	July 31, 2014	August 15, 2014
September 30, 2014	$ 0.44	October 15, 2014	October 31, 2014	November 17, 2014
December 31, 2014	$ 0.45	January 21, 2015	February 2, 2015	February 17, 2015

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As disclosed elsewhere in this report, we expect to pay cash dividends totaling $2.00 per share on our common stock for 2015. There is nothing in our governing documents or credit agreements that prohibits us from borrowing to pay dividends. The actual amount of dividends to be paid on our capital stock will depend on many factors, including our financial condition and results of operations, liquidity requirements, business prospects, capital requirements, legal, regulatory and contractual constraints, tax laws, Delaware laws and other factors. See Item 1A. "Risk Factors—The guidance we provide for our anticipated dividends is based on estimates. Circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business." All of these matters will be taken into consideration by our board of directors in declaring dividends.

Our 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 dividends generally will be paid on or about the 16th day of each February, May, August and November.

Recent Accounting Pronouncements

Please refer to Note 17 "Recent Accounting Pronouncements" to our consolidated financial statements for information concerning recent accounting pronouncements.

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

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

Energy Commodity Market Risk

We are exposed to energy commodity market risk and other external risks in the ordinary course of business. However, we take steps to hedge, or limit our exposure to, these risks by executing a hedging strategy that seeks to protect us financially against adverse price movements and serves to minimize potential losses. Our strategy involves the use of certain energy commodity derivative contracts to reduce and minimize the risks associated with unfavorable changes in the market price of natural gas, NGL and crude oil. The derivative contracts that we use include energy products traded on the NYMEX and OTC markets, including, but not limited to, futures and options contracts, fixed price swaps and basis swaps.

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As part of the EP acquisition, we acquired power forward and swap contracts. We have entered into offsetting positions that eliminate the price risks associated with our power contracts. None of these derivatives are designated as accounting hedges.
Fundamentally, our hedging strategy involves taking a simultaneous financial position in the futures market that is equal and opposite to our physical position, or anticipated position, in the cash market (or physical product) in order to minimize the risk of financial loss from an adverse price change. For example, as sellers of crude oil and natural gas, we often enter into fixed price swaps and/or futures contracts to guarantee or lock-in the sale price of our crude oil or the margin from the sale and purchase of our natural gas at the time of market delivery, thereby in whole or in part offsetting any change in prices, either positive or negative. A hedge is successful to the extent gains or losses in the cash market are neutralized by losses or gains in the futures transaction.

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

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

	Credit Rating
Bank of America / Merrill Lynch	A-
J. Aron & Company / Goldman Sachs	A-
J.P. Morgan	A
Morgan Stanley	A-
Macquarie	BBB

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As discussed above, the principal use of energy commodity derivative contracts is to mitigate the market price risk associated with anticipated transactions for the purchase and sale of natural gas, NGL and crude oil. Using derivative contracts for this purpose helps provide increased certainty with regard to operating cash flows which helps us to undertake further capital improvement projects, attain budget results and meet dividend targets. We may categorize such use of energy commodity derivative contracts as cash flow hedges because the derivative contract is used to hedge the anticipated future cash flow of a transaction that is expected to occur but which value is uncertain. Cash flow hedges are defined as hedges made with the intention of decreasing the variability in cash flows related to future transactions, as opposed to the value of an asset, liability or firm commitment, and we are allowed special hedge accounting treatment for such derivative contracts.

In accounting for cash flow hedges, gains and losses on the derivative contracts are reported in other comprehensive income, outside "Net Income" reported in our consolidated statements of income, but only to the extent that the gains and losses from the change in value of the derivative contracts can later offset the loss or gain from the change in value of the hedged future cash flows during the period in which the hedged cash flows affect net income. That is, for cash flow hedges, all effective components of the derivative contracts' gains and losses are recorded in other comprehensive income, pending occurrence of the expected transaction. Other comprehensive income consists of those financial items that are within "Accumulated other comprehensive loss" in our accompanying consolidated balance sheets but not included in our net income (portions attributable to our noncontrolling interests are within "Noncontrolling interests" and are not included in our net income). Thus, in highly effective cash flow hedges, where there is no ineffectiveness, other comprehensive income changes by exactly as much as the derivative contracts and there is no impact on earnings until the expected transaction occurs.

All remaining gains and losses on the derivative contracts (the ineffective portion and those contracts not designated as hedges) are included in current net income. The ineffective portion of the gain or loss on the derivative contracts is the difference between the gain or loss from the change in value of the derivative contract and the effective portion of that gain or loss. In addition, when the hedged forecasted transaction does take place and affects earnings, the effective part of the hedge is also recognized in the income statement, and the earlier recognized effective amounts are removed from "Accumulated other comprehensive loss" (and "Noncontrolling interests") and are transferred to the income statement as well, effectively offsetting the changes in cash flows stemming from the hedged risk. If the forecasted transaction results in an asset or liability, amounts

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should be reclassified into earnings when the asset or liability affects earnings through cost of sales, depreciation, interest expense, etc.

We measure the risk of price changes in the natural gas, NGL, crude oil and power derivative instruments portfolios utilizing a sensitivity analysis model. The sensitivity analysis applied to each portfolio measures the potential income or loss (i.e., the change in fair value of the derivative instrument portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values. As of December 31, 2014 and 2013, a hypothetical 10% movement in underlying commodity natural gas prices would affect the estimated fair value of natural gas derivatives by $9 million and $15 million, respectively. As of December 31, 2014 and 2013, a hypothetical 10% movement in underlying commodity crude oil prices would affect the estimated fair value of crude oil derivative by $146 million and $201 million, respectively. As of December 31, 2014 and 2013, a hypothetical 10% movement in underlying commodity NGL prices would affect the estimated fair value of our NGL derivatives by $0.3 million and $5 million, respectively. As of both December 31, 2014 and 2013, a hypothetical 10% movement in underlying commodity electricity prices would not affect the estimated fair value of our power derivatives. As discussed above, we enter into derivative contracts largely for the purpose of mitigating the risks that accompany certain of our business activities and, therefore both in the sensitivity analysis model and in reality, the change in the market value of the derivative contracts portfolio is offset largely by changes in the value of the underlying physical transactions.

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

Interest Rate Risk

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

For fixed rate debt, changes in interest rates generally affect the fair value of the debt instrument, but not our earnings or cash flows. Conversely, for variable rate debt, changes in interest rates generally do not impact the fair value of the debt instrument, but may affect our future earnings and cash flows. Generally, there is not an obligation to prepay fixed rate debt prior to maturity and, as a result, interest rate risk and changes in fair value should not have a significant impact on the fixed rate debt until we would be required to refinance such debt.

As of December 31, 2014 and 2013, the carrying values of the fixed rate debt (including the debt fair value adjustments) were $41,538 million and $33,129 million, respectively. These amounts compare to, as of December 31, 2014 and 2013, fair values of $42,164 million and $33,185 million, respectively. Fair values were determined using quoted market prices, where applicable, or future cash flow discounted at market rates for similar types of borrowing arrangements. A hypothetical 10% change in the average interest rates applicable to such debt for 2014 and 2013, would result in changes of approximately $1,539 million and $1,185 million, respectively, in the fair values of these instruments.

The carrying value of the variable rate debt (which approximates the fair value), excluding the value of interest rate swap agreements (discussed following), was $1,425 million and $3,064 million as of December 31, 2014 and 2013, respectively. As of December 31, 2014 and 2013 we were party to interest rate swap agreements with notional principal amounts of $9,200 million and $5,400 million, respectively. An interest rate swap agreement is a contractual agreement entered into between two counterparties under which each agrees to make periodic interest payments to the other for an agreed period of time based upon a predetermined amount of principal, which is called the notional principal amount. Normally at each payment or settlement date, the party who owes more pays the net amount; so at any given settlement date only one party actually makes a payment. The principal amount is notional because there is no need to exchange actual amounts of principal. A hypothetical 10% change in the weighted average interest rate on all of our borrowings (approximately 50 basis points in 2014 and approximately 51 basis points in 2013) when applied to our outstanding balance of variable rate debt as of December 31, 2014 and 2013, including adjustments for the notional swap amounts described above, would result in changes of approximately $53 million and $43 million, respectively, in our 2014 and 2013 annual pre-tax earnings.

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

We monitor the mix of fixed rate and variable rate debt obligations in light of changing market conditions and from time to time, may alter that mix by, for example, refinancing outstanding balances of variable rate debt with fixed rate debt (or vice versa) or by entering into interest rate swap agreements or other interest rate hedging agreements. As of December 31, 2014, approximately 26% is variable rate debt.

For more information on our interest rate risk management and on our interest rate swap agreements, see Note 13 “Risk Management” to our consolidated financial statements.

Item 8. Financial Statements and Supplementary Data.

The information required in this Item 8 is in this report as set forth in the “Index to Financial Statements” on page 77.

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

None.

Item 9A. Controls and Procedures.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2014, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management’s Report on Internal Control Over Financial Reporting

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

Commission. Based on this assessment, our management concluded that our internal control over financial reporting was effective as of December 31, 2014.

The effectiveness of our internal control over financial reporting as of December 31, 2014, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their audit report, which appears herein.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.
The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2015 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2015.

Item 11. Executive Compensation.
The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2015 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2015.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.
The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2015 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2015.

Item 13. Certain Relationships and Related Transactions, and Director Independence.
The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2015 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2015.

Item 14. Principal Accounting Fees and Services.

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2015 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2015.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements and (2) Financial Statement Schedules
See "Index to Financial Statements" set forth on Page 77.

(3) Exhibits

Exhibit Number		Description
2.1	*	Agreement and Plan of Merger, dated as of August 9, 2014, by and among Kinder Morgan Energy Partners, L.P., Kinder Morgan G.P., Inc., Kinder Morgan Management, LLC, Kinder Morgan, Inc., and P Merger Sub LLC (schedules omitted pursuant to Item 601(b)(2) of Regulation S-K) (filed as Exhibit 2.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K (File No. 1-35081), filed August 12, 2014)
2.2	*	Agreement and Plan of Merger, dated as of August 9, 2014, by and among Kinder Morgan Management, LLC, Kinder Morgan, Inc., and R Merger Sub LLC (schedules omitted pursuant to Item 601(b)(2) of Regulation S-K) (filed as Exhibit 2.2 to Kinder Morgan, Inc.'s Current Report on Form 8-K (File No. 1-35081), filed August 12, 2014)

2.3	*	Agreement and Plan of Merger, dated as of August 9, 2014, by and among El Paso Pipeline Partners, L.P., El Paso Pipeline GP Company, L.L.C., Kinder Morgan, Inc., and E Merger Sub LLC (schedules omitted pursuant to Item 601(b)(2) of Regulation S-K) (filed as Exhibit 2.3 to Kinder Morgan, Inc.'s Current Report on Form 8-K (File No. 1-35081), filed August 12, 2014)
3.1		Certificate of Incorporation of Kinder Morgan, Inc. as amended by the Certificate of Amendment to the Certificate of Incorporation

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3.2		Amended and Restated Bylaws of Kinder Morgan, Inc. as amended by the Amendment No. 1 to the Amended and Restated Bylaws
4.1	*	Form of certificate representing Class P common shares of Kinder Morgan, Inc. (filed as Exhibit 4.1 to Kinder Morgan, Inc.'s Registration Statement on Form S-1 filed on January 18, 2011 (File No. 333-170773))
4.2	*	Shareholders Agreement among Kinder Morgan, Inc. and certain holders of common stock (filed as Exhibit 4.2 to the KMI 10-Q)
4.3	*	Amendment No. 1 to the Shareholders Agreement among Kinder Morgan, Inc. and certain holders of common stock (filed as Exhibit 4.3 Kinder Morgan, Inc.'s Current Report on Form 8-K filed on May 30, 2012 (File No. 1-35081))
4.4	*	Amendment No. 2 to the Shareholders Agreement among Kinder Morgan, Inc. and certain holders of common stock (filed as Exhibit 4.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on December 3, 2014 (File No. 1-35081))
4.5	*	Warrant Agreement, dated as of May 25, 2012, among Kinder Morgan, Inc., Computershare Trust Company, N.A. and Computershare Inc., as Warrant Agent (filed as Exhibit 4.1 to Kinder Morgan Inc.'s Current Report on Form 8-K filed on May 30, 2012 (File No. 1-35081))
10.1	*	Kinder Morgan, Inc. 2011 Stock Incentive Plan (filed as Exhibit 10.1 to the KMI 10-Q)
10.2	*	Form of Restricted Stock Agreement (filed as Exhibit 10.2 to the KMI 10-Q)
10.3	*	Kinder Morgan, Inc. Stock Compensation Plan for Non-Employee Directors (filed as Exhibit 10.4 to the KMI 10-Q)
10.4	*	Form of Non-Employee Director Stock Compensation Agreement (filed as Exhibit 10.3 to the KMI 10-Q)
10.5	*	Kinder Morgan, Inc. Employees Stock Purchase Plan (filed as Exhibit 10.5 to the KMI 10-Q)
10.6	*	Kinder Morgan, Inc. Annual Incentive Plan (filed as Exhibit 10.6 to the KMI 10-Q)
10.7	*	Employment Agreement dated October 7, 1999, between K N Energy, Inc. and Richard D. Kinder (filed as Exhibit 99.D of the Schedule 13D filed by Mr. Kinder on November 16, 1999 (File No. 5-06259))
10.8	*	Credit Agreement, dated as of May 30, 2007, among Kinder Morgan Kansas, Inc. and Kinder Morgan Acquisition Co., as the borrower, the several lenders from time to time parties thereto, and Citibank, N.A., as administrative agent and collateral agent (filed as Exhibit 10.10 to Kinder Morgan, Inc.'s Registration Statement on Form S-1 filed on December 30, 2010 (File No. 333-170773))
10.9	*	Registration Rights Agreement among Kinder Morgan Management, LLC, Kinder Morgan Energy Partners, L.P. and Kinder Morgan Kansas, Inc. dated May 18, 2001 (filed as Exhibit 4.7 to Kinder Morgan Kansas, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 1-06446))
10.10	*	Form of Indenture dated as of August 27, 2002 between Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Registration

		Statement on Form S-4 filed on October 4, 2002 (File No. 333-100338))
10.11	*	Form of First Supplemental Indenture dated as of December 6, 2002 between Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-4 filed on January 31, 2003 (File No. 333-102873))
10.12	*	Form of 6.50% Note due 2012 (included in the Indenture filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100338))
10.13	*	Form of Senior Indenture between Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102963))
10.14	*	Form of Senior Note of Kinder Morgan Kansas, Inc. (included in the Form of Senior Indenture filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102963))
10.15	*	Indenture dated as of December 9, 2005, among Kinder Morgan Finance Company LLC (formerly Kinder Morgan Finance Company, ULC), Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 15, 2005 (File No. 1-06446))

10.16	*	Forms of Kinder Morgan Finance Company LLC Notes (included in the Indenture filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 15, 2005 (File No. 1-06446))
10.17	*	Form of Indemnification Agreement between Kinder Morgan Kansas, Inc. and each member of the Special Committee of the Board of Directors formed in connection with the Going Private Transaction (filed as Exhibit 10.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on June 16, 2006 (File No. 1-06446))
10.18	*	Delegation of Control Agreement among Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan Energy Partners, L.P. and its operating partnerships (filed as Exhibit 10.1 to the Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2001 (File No. 1-11234))
10.19	*	Amendment No. 1 to Delegation of Control Agreement, dated as of July 20, 2007, among Kinder Morgan G.P., Inc., Kinder Morgan Management, LLC, Kinder Morgan Energy Partners, L.P. and its operating partnerships (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K on July 20, 2007 (File No. 1-11234))
10.20	*	Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 3.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2001 (File No. 1-11234))
10.21	*	Amendment No. 1 dated November 19, 2004 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 99.1 to Kinder Morgan Energy Partners, L.P. Form 8-K filed November 22, 2004 (File No. 1-11234))
10.22	*	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 99.1 to Kinder Morgan Energy Partners, L.P. Form 8-K filed May 5, 2005 (File No. 1-11234))
10.23	*	Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 3.1 to Kinder Morgan Energy Partners, L.P. Form 8-K filed April 21, 2008 (File No. 1-11234))
10.24	*	Amendment No. 4 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 3.5 to Kinder Morgan Energy Partners, L.P. Form 10-K 2012 (File No. 1-11234))
10.25	*	Credit Agreement dated as of June 23, 2010 among Kinder Morgan Energy Partners, L.P., Kinder Morgan Operating L.P. "B", the lenders party thereto, Wells Fargo Bank, National Association as Administrative Agent, Bank of America, N.A., Citibank, N.A., JPMorgan Chase Bank, N.A., and DnB NOR Bank ASA (filed as exhibit 10.1 to Kinder Morgan Energy Partners, L.P. Current Report on Form 8-K filed June 24, 2010 (File No. 1-11234))
10.26	*	First Amendment to Credit Agreement, dated as of July 1, 2011, among Kinder Morgan Energy Partners, L.P., Kinder Morgan Operating L.P. "B", the lenders party thereto and Wells Fargo Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 (File No. 1-11234))

10.27	*	Indenture dated as of January 29, 1999 among Kinder Morgan Energy Partners, L.P., the guarantors listed on the signature page thereto and U.S. Trust Company of Texas, N.A., as trustee, relating to Senior Debt Securities (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed February 16, 1999 (File No. 1-11234))
10.28	*	Indenture dated November 8, 2000 between Kinder Morgan Energy Partners, L.P. and First Union National Bank, as Trustee (filed as Exhibit 4.8 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-11234))
10.29	*	Indenture dated January 2, 2001 between Kinder Morgan Energy Partners, L.P. and First Union National Bank, as trustee, relating to Senior Debt Securities (including form of Senior Debt Securities) (filed as Exhibit 4.11 to Kinder Morgan Energy Partners, L.P. Annual Report on Form 10-K for the year ended December 31, 2000 (File No. 1-11234))
10.30	*	Certificate of Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 6.75% Notes due March 15, 2011 and the 7.40% Notes due March 15, 2031 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Current Report on Form 8-K filed on March 14, 2001 (File No. 1-11234))
10.31	*	Specimen of 7.40% Notes due March 15, 2031 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P. Current Report on Form 8-K filed on March 14, 2001(File No. 1-11234))

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10.32	*	Certificate of Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 7.125% Notes due March 15, 2012 and the 7.750% Notes due March 15, 2032 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234))
10.33	*	Specimen of 7.750% Notes due March 15, 2032 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P. Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234))
10.34	*	Indenture dated August 19, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to the Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
10.35	*	First Supplemental Indenture to Indenture dated August 19, 2002, dated August 23, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
10.36	*	Form of 7.30% Note (contained in the Indenture filed as Exhibit 4.1 to the Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
10.37	*	Senior Indenture dated January 31, 2003 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association (filed as Exhibit 4.2 to the Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961))
10.38	*	Form of Senior Note of Kinder Morgan Energy Partners, L.P. (included in the Form of Senior Indenture filed as Exhibit 4.2 to the Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961))
10.39	*	Certificate of Vice President, Treasurer and Chief Financial Officer and Vice President, General Counsel and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 5.80% Notes due March 15, 2035 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 (File No. 1-11234))
10.40	*	Certificate of Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 6.00% Senior Notes due 2017 and 6.50% Senior Notes due 2037 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P. Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 1-11234))
10.41	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 6.95% Senior Notes due 2038 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 (File No. 1-11234))
10.42	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy

		Partners, L.P., establishing the terms of the 5.95% Senior Notes due 2018 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P. Annual Report on Form 10-K for the year ended December 31, 2007 (File No. 1-11234))
10.43	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 9.00% Senior Notes due 2019 (filed as Exhibit 4.29 to Kinder Morgan Energy Partners, L.P. Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 1-11234))
10.44	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.625% Senior Notes due 2015, and the 6.85% Senior Notes due 2020 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Quarterly Report on Form 10-Q for the quarter ended June 30, 2009 (File No. 1-11234))
10.45	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.80% Senior Notes due 2021, and the 6.50% Senior Notes due 2039 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Quarterly Report on Form 10-Q for the quarter ended September 30, 2009 (File No. 1-11234))
10.46	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.30% Senior Notes due 2020, and the 6.55% Senior Notes due 2040 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 (File No. 1-11234))

10.47	*	Indenture, dated December 20, 2010, among Kinder Morgan Finance Company LLC, Kinder Morgan Kansas, Inc. and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 23, 2010 (File No. 1-06446))
10.48	*	Officers' Certificate establishing the terms of the 6.000% Senior Notes due 2018 of Kinder Morgan Finance Company LLC (with the form of note attached thereto) (filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 23, 2010 (File No. 1-06446))
10.49	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 3.500% Senior Notes due 2016, and the 6.375% Senior Notes due 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 1-11234))
10.50	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.150% Senior Notes due 2022, and the 5.625% Senior Notes due 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 1-11234))
10.51	*	Certificate of the Vice President, Finance and Investor Relations and the Vice President and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 3.500% Senior Notes due 2021 and the 5.500% Senior Notes due 2044 (Filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2014 (File No. 1-11234))
10.52	*	Certificate of the Vice President and Treasurer and the Vice President and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.250% Senior Notes due 2024 and the 5.400% Senior Notes due 2044 (Filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2014 (File No. 1-11234))
10.53		Certificate of the Vice President and Treasurer and the Vice President and Secretary of Kinder Morgan, Inc. establishing the terms of the 2.000% Senior Notes due 2017, the 3.050% Senior Notes due 2019, the 4.300% Senior Notes due 2025, the 5.300% Senior Notes due 2034 and the 5.550% Senior Notes due 2045
10.54	*	Debt Commitment Letter between Kinder Morgan, Inc. and Barclays Capital PLC, dated as of October 16, 2011 (filed as Exhibit 10.71 to Kinder Morgan, Inc.'s Registration Statement on Form S-4 filed on December 14, 2011 (File No. 333-177895))
10.55	*	Support Agreement, dated as of August 9, 2014, by and among Kinder Morgan Energy Partners, L.P., Kinder Morgan G.P., Inc., Kinder Morgan Management, LLC, El Paso Pipeline Partners, L.P., El Paso Pipeline GP Company, L.L.C., Richard D. Kinder and RDK Investments, Ltd. (filed as Exhibit 10.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K (File No. 1-35081), filed August 12, 2014)
10.56	*	Bridge Credit Agreement, dated September 19, 2014 among Kinder Morgan, Inc., as borrower, Barclays Bank PLC, as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to Kinder Morgan,

		Inc.'s Current Report on Form 8-K (File No. 1-35081), filed September 25, 2014)
10.57	*	Revolving Credit Agreement, dated September 19, 2014 among Kinder Morgan, Inc., as borrower, Barclays Bank PLC, as administrative agent, and the lenders and issuing banks party thereto (filed as Exhibit 10.2 to Kinder Morgan, Inc.'s Current Report on Form 8-K (File No. 1-35081), filed September 25, 2014)
10.58		Cross Guarantee Agreement, dated as of November 26, 2014 among Kinder Morgan, Inc. and certain of its subsidiaries with schedules updated as of February 13, 2015
12.1		Statement re: computation of ratio of earnings to fixed charges
21.1		Subsidiaries of Kinder Morgan, Inc.
23.1		Consent of PricewaterhouseCoopers LLP
23.2		Consent of Netherland, Sewell & Associates, Inc.
31.1		Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2		Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

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32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
95.1	Mine Safety Disclosures
99.1	Netherland, Sewell & Associates, Inc.'s report of estimates of the net reserves and future net revenues, as of December 31, 2014, related to Kinder Morgan CO_2 Company, L.P.'s interest in certain oil and gas properties located in the state of Texas
101	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the years ended December 31, 2014, 2013, and 2012; (ii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2014, 2013, and 2012; (iii) our Consolidated Balance Sheets as of December 31, 2014 and 2013; (iv) our Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013, and 2012; (v) our Consolidated Statement of Stockholders' Equity as of and for the years ended December 31, 2014, 2013, and 2012; and (vi) the notes to our Consolidated Financial Statements

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

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KINDER MORGAN, INC. AND SUBSIDIARIES
INDEX TO FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of comprehensive income, of stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Kinder Morgan, Inc. and its subsidiaries (the "Company") at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing in Item 9A of the Company's 2014 Annual Report on Form 10-K. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 23, 2015

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

	Year Ended December 31,		
	2014	2013	2012
Revenues			
Natural gas sales	$4,115	$3,605	$2,511
Services	7,650	6,677	5,013
Product sales and other	4,461	3,788	2,449
Total Revenues	16,226	14,070	9,973
Operating Costs, Expenses and Other			
Costs of sales	6,278	5,253	3,057
Operations and maintenance	2,157	2,112	1,702
Depreciation, depletion and amortization	2,040	1,806	1,419
General and administrative	610	613	929
Taxes, other than income taxes	418	395	286
Loss on impairments of long-lived assets	272	—	—
Other expense (income), net	3	(99)	(13)
Total Operating Costs, Expenses and Other	11,778	10,080	7,380
Operating Income	4,448	3,990	2,593
Other Income (Expense)			
Earnings from equity investments	406	327	153
Amortization of excess cost of equity investments	(45)	(39)	(23)
Interest, net	(1,798)	(1,675)	(1,399)
Gain on remeasurement of previously held equity investments to fair value (Note 3)	—	558	—
Gain on sale of investments in Express pipeline system (Note 3)	—	224	—
Other, net	80	53	19
Total Other Income (Expense)	(1,357)	(552)	(1,250)
Income from Continuing Operations Before Income Taxes	3,091	3,438	1,343
Income Tax Expense	(648)	(742)	(139)
Income from Continuing Operations	2,443	2,696	1,204
Discontinued Operations (Note 3)			
Income from operations of the FTC Natural Gas Pipelines disposal group and other, net of tax	—	—	160
Loss on sale and the remeasurement of the FTC Natural Gas Pipelines disposal group to fair value, net of tax	—	(4)	(937)
Loss from Discontinued Operations, Net of Tax	—	(4)	(777)
Net Income	2,443	2,692	427
Net Income Attributable to Noncontrolling Interests	(1,417)	(1,499)	(112)

Net Income Attributable to Kinder Morgan, Inc.	$1,026	$1,193	$315

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

	Year Ended December 31,		
	2014	2013	2012
Class P Shares			
Basic and Diluted Earnings Per Common Share From Continuing Operations	$0.89	$1.15	$0.56
Basic and Diluted Loss Per Common Share From Discontinued Operations	—	—	(0.21)
Total Basic and Diluted Earnings Per Common Share	$0.89	$1.15	$0.35
Class A Shares			
Basic and Diluted Earnings Per Common Share From Continuing Operations			$0.47
Basic and Diluted Loss Per Common Share From Discontinued Operations			(0.21)
Total Basic and Diluted Earnings Per Common Share			$0.26
Basic Weighted-Average Number of Shares Outstanding			
Class P Shares	1,137	1,036	461
Class A Shares			446
Diluted Weighted-Average Number of Shares Outstanding			
Class P Shares	1,137	1,036	908
Class A Shares			446
Dividends Per Common Share Declared for the Period	$1.74	$1.60	$1.40

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

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

	Year Ended December 31,		
	2014	2013	2012
Kinder Morgan, Inc.			
Net income	$1,026	$1,193	$315
Other comprehensive income (loss), net of tax			
Change in fair value of derivatives utilized for hedging purposes (net of tax (expense) benefit of $(150), $6 and $(19), respectively)	254	(14)	32
Reclassification of change in fair value of derivatives to net income (net of tax benefit (expense) of $13, $(2) and $3, respectively)	(22)	4	(5)
Foreign currency translation adjustments (net of tax benefit (expense) of $41, $22, and $(8), respectively)	(68)	(49)	14
Benefit plan adjustments (net of tax benefit (expense) of $125, $(88) and $30, respectively)	(213)	153	(44)
Total other comprehensive (loss) income	(49)	94	(3)
Total comprehensive income	977	1,287	312
Noncontrolling Interests			
Net income	1,417	1,499	112
Other comprehensive income (loss), net of tax			
Change in fair value of derivatives utilized for hedging purposes (net of tax (expense) benefit of $(13), $4 and $(7), respectively)	155	(24)	50
Reclassification of change in fair value of derivatives to net income (net of tax benefit (expense) of $-, $(1) and $-, respectively)	(3)	7	(3)
Foreign currency translation adjustments (net of tax benefit (expense) of $7, $9 and $(2), respectively)	(70)	(54)	18
Benefit plan adjustments (net of tax benefit (expense) of $1, $(3) and $-, respectively)	(13)	17	9
Total other comprehensive income (loss)	69	(54)	74
Total comprehensive income	1,486	1,445	186
Total			
Net income	2,443	2,692	427
Other comprehensive income (loss), net of tax			
Change in fair value of derivatives utilized for hedging purposes (net of tax (expense) benefit of $(163), $10 and $(26), respectively)	409	(38)	82
Reclassification of change in fair value of derivatives to net income (net of tax benefit (expense) of $13, $(3) and $3, respectively)	(25)	11	(8)
Foreign currency translation adjustments (net of tax benefit (expense) of $48, $31 and $(10), respectively)	(138)	(103)	32
Benefit plan adjustments (net of tax benefit (expense) of $126, $(91) and $30, respectively)	(226)	170	(35)
Total other comprehensive income	20	40	71
Total comprehensive income	$2,463	$2,732	$498

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

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

	December 31, 2014	2013
ASSETS		
Current assets		
Cash and cash equivalents	$315	$598
Accounts receivable, net	1,641	1,721
Fair value of derivative contracts	535	116
Inventories	459	430
Deferred income taxes	56	567
Other current assets	746	436
Total current assets	3,752	3,868
Property, plant and equipment, net	38,564	35,847
Investments	6,036	5,951
Goodwill	24,654	24,504
Other intangibles, net	2,302	2,438
Deferred income taxes	5,651	—
Deferred charges and other assets	2,239	2,577
Total Assets	$83,198	$75,185
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of debt	$2,717	$2,306
Accounts payable	1,588	1,676
Accrued interest	637	565
Accrued contingencies	383	584
Other current liabilities	1,037	944
Total current liabilities	6,362	6,075
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	38,212	31,810
Preferred interest in general partner of KMP	100	100
Debt fair value adjustments	1,934	1,977
Total long-term debt	40,246	33,887
Deferred income taxes	—	4,651
Other long-term liabilities and deferred credits	2,164	2,287
Total long-term liabilities and deferred credits	42,410	40,825
Total Liabilities	$48,772	$46,900

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

	December 31, 2014	2013
Commitments and contingencies (Notes 8, 12 and 16)		
Stockholders' Equity		
Class P shares, $0.01 par value, 4,000,000,000 and 2,000,000,000 shares, respectively, authorized, 2,125,147,116 and 1,030,677,076 shares, respectively, issued and outstanding	$ 21	$ 10
Preferred stock, $0.01 par value, 10,000,000 shares authorized, none outstanding	—	—
Additional paid-in capital	36,178	14,479
Retained deficit	(2,106)	(1,372)
Accumulated other comprehensive loss	(17)	(24)
Total Kinder Morgan, Inc.'s stockholders' equity	34,076	13,093
Noncontrolling interests	350	15,192
Total Stockholders' Equity	34,426	28,285
Total Liabilities and Stockholders' Equity	$ 83,198	$ 75,185

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

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

	Year Ended December 31,		
	2014	2013	2012
Cash Flows From Operating Activities			
Net income	$2,443	$2,692	$427
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	2,040	1,806	1,426
Deferred income taxes	615	640	47
Amortization of excess cost of equity investments	45	39	23
Loss on impairments of long-lived assets	272	—	—
(Gain) loss from the remeasurement of net assets to fair value and the sale of discontinued operations (net of cash selling expenses), net of tax (Note 3)	—	(556)	859
Gain from sale of investments in Express pipeline system (Note 3)	—	(224)	—
Loss on early extinguishment of debt	—	—	82
Noncash compensation expense on settlement of EP stock awards	—	—	87
Earnings from equity investments	(406)	(327)	(223)
Distributions from equity investment earnings	381	398	381
Proceeds from termination of interest rate swap agreements	—	96	53
Pension contributions and noncash pension benefit credits	(88)	(120)	(31)
Changes in components of working capital, net of the effects of acquisitions			
Accounts receivable	(84)	(131)	(231)
Income tax receivable	(195)	—	—
Inventories	(30)	(53)	(92)
Other current assets	(31)	(24)	32
Accounts payable	(1)	(36)	70
Accrued interest	75	42	(26)
Accrued contingencies and other current liabilities	108	(100)	(68)
Rate reparations, refunds and other litigation reserve adjustments	(280)	174	(39)
Other, net	(397)	(194)	31
Net Cash Provided by Operating Activities	4,467	4,122	2,808
Cash Flows From Investing Activities			
Acquisition of EP, net of $6,581 cash acquired (Note 3)	—	—	(4,970)
Acquisitions of other assets and investments, net of cash acquired	(1,388)	(292)	(83)
Proceeds from sales of assets and investments	—	490	—
Proceeds from disposal of discountinued operations (Note 3)	—	—	1,791
Capital expenditures	(3,617)	(3,369)	(2,022)
Sale or casualty of property, plant and equipment, investments and other net assets, net of removal costs	5	87	154
Contributions to investments	(389)	(217)	(192)
Distributions from equity investments in excess of cumulative earnings	182	185	200
Other, net	(3)	(6)	25
Net Cash Used in Investing Activities	(5,210)	(3,122)	(5,097)

Cash Flows From Financing Activities			
Issuance of debt	24,573	13,581	18,148
Payment of debt	(17,801)	(12,393)	(14,755)
Debt issue costs	(89)	(38)	(111)
Cash dividends (Note 10)	(1,760)	(1,622)	(1,184)
Repurchases of shares and warrants	(192)	(637)	(157)
Cash consideration of Merger Transactions (Note 1)	(3,937)	—	—
Merger Transactions costs	(74)	—	—
Contributions from noncontrolling interests	1,767	1,706	1,939
Distributions to noncontrolling interests	(2,013)	(1,692)	(1,219)
Other, net	(3)	—	(77)
Net Cash Provided by (Used in) Financing Activities	471	(1,095)	2,584
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(11)	(21)	8
Net (decrease) increase in Cash and Cash Equivalents	(283)	(116)	303
Cash and Cash Equivalents, beginning of period	598	714	411
Cash and Cash Equivalents, end of period	$315	$598	$714

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

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

	Year Ended December 31,		
	2014	2013	2012
Noncash Investing and Financing Activities			
Net assets and liabilities or noncontrolling interests acquired by the issuance of shares and warrants (Notes 1 and 3)	$16,023	$—	$11,454
Assets acquired by the assumption or incurrence of liabilities	106	1,510	—
Assets acquired or liabilities settled by contributions from noncontrolling interests	—	3,733	306
Supplemental Disclosures of Cash Flow Information			
Cash paid during the period for interest (net of capitalized interest)	1,718	1,652	1,349
Cash paid during the period for income taxes (net of refunds)	227	67	182

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

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

	Par value of common shares	Additional paid-in capital	Retained deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
Balance at December 31, 2011	$8	$3,431	$(3)	$ (115)	$3,321	$ 5,247	$8,568
Issuance of shares for EP acquisition	3	10,598			10,601		10,601
Issuance of warrants for EP acquisition		863			863		863
Acquisition of EP noncontrolling interests					—	3,797	3,797
Warrants repurchased		(157)			(157)		(157)
EP Trust I Preferred security conversions		14			14		14
Class A, Class B and Class C share conversions	(1)	1	(71)		(71)		(71)
Amortization of restricted shares		14			14		14
Impact from equity transactions of KMP, EPB and KMR		64			64	(102)	(38)
Tax impact on stock based compensation		90			90		90
Net income			315		315	112	427
Distributions					—	(1,219)	(1,219)
Contributions					—	2,329	2,329
Cash dividends			(1,184)		(1,184)		(1,184)
Other		(1)			(1)	(4)	(5)
Other comprehensive (loss) income				(3)	(3)	74	71
Balance at December 31, 2012	10	14,917	(943)	(118)	13,866	10,234	24,100
Shares repurchased		(172)			(172)		(172)
Warrants repurchased		(465)			(465)		(465)
Warrants exercised		1			1		1
EP Trust I Preferred security conversions		3			3		3
Amortization of restricted shares		35			35		35
Impact from equity transactions of KMP, EPB and KMR		161			161	(254)	(93)
Net income			1,193		1,193	1,499	2,692
Distributions					—	(1,692)	(1,692)
Contributions					—	5,439	5,439
KMP's acquisition of Copano noncontrolling interests					—	17	17
Cash dividends			(1,622)		(1,622)		(1,622)
Other		(1)			(1)	3	2
Other comprehensive income				94	94	(54)	40
Balance at December 31, 2013	10	14,479	(1,372)	(24)	13,093	15,192	28,285
Impact of Merger Transactions	11	21,880			21,891	(15,936)	5,955
Merger Transactions costs		(75)			(75)		(75)
Shares repurchased		(94)			(94)		(94)

Warrants repurchased		(98)			(98)		(98)
Amortization of restricted shares		57			57		57
Impact from equity transactions of KMP, EPB and KMR		36			36	(55)	(19)
Net income			1,026		1,026	1,417	2,443
Distributions					—	(2,013)	(2,013)
Contributions					—	1,767	1,767
Cash dividends			(1,760)		(1,760)		(1,760)
Other		(7)			(7)	(4)	(11)
Other comprehensive (loss) income				(49)	(49)	69	20
Impact of Merger Transactions on Accumulated other comprehensive loss				56	56	(87)	(31)
Balance at December 31, 2014	$21	$36,178	$(2,106)	$ (17)	$34,076	$ 350	$34,426

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

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KINDER MORGAN, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General

We are the largest energy infrastructure and the third largest energy company in North America with an enterprise value of more than $125 billion and unless the context requires otherwise, references to “we,” “us,” “our,” or “KMI” are intended to mean Kinder Morgan, Inc. and its consolidated subsidiaries. We own an interest in or operate approximately 80,000 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, 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 Kinder Morgan Energy Partners, L.P. (NYSE: KMP) and El Paso Pipeline Partners, L.P. (NYSE: EPB) and all of the outstanding shares of Kinder Morgan Management, LLC (NYSE: KMR) that we did not already own. The transactions, valued at approximately $77 billion, are referred to collectively as the “Merger Transactions.”

Upon completion of the Merger Transactions: (i) each publicly held KMR share received 2.4849 shares of KMI common stock; (ii) through the election and proration mechanisms in the KMP merger agreement, on average, each common unit held by a public KMP unitholder received 2.1931 shares of KMI common stock and $10.77 in cash; and (iii) through the election and proration mechanisms in the EPB merger agreement, on average, each common unit held by a public EPB unitholder received 0.9451 shares of KMI common stock and $4.65 in cash. The cash payments to the public unitholders of KMP and EPB totaled approximately $3.9 billion.

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

Prior to November 26, 2014, we owned an approximate 10% limited partner interest (including our interest in KMR) and the 2% general partner interest including incentive distribution rights in KMP, and an approximate 39% limited partner interest and the 2% general partner interest and incentive distribution rights in EPB. Effective with the Merger Transactions, the incentive distribution rights held by the general partner of KMP was eliminated.

The equity interests in KMP, EPB and KMR (which are all consolidated in our financial statements) owned by the public prior to November 26, 2014 are reflected within “Noncontrolling interests” in our accompanying December 31, 2013 consolidated balance sheet. The earnings recorded by KMP, EPB and KMR that are attributed to their units and shares, respectively, held by the public prior to November 26, 2014 are reported as “Net income attributable to noncontrolling interests” in our accompanying consolidated statements of income.

Our common stock trades on the NYSE under the symbol “KMI.”

2. Summary of Significant Accounting Policies

Basis of Presentation

Our reporting currency is U.S. dollars, and all references to dollars are U.S. dollars.

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

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Use of Estimates

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

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

Cash Equivalents and Restricted Deposits

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

Restricted cash of $118 million and $75 million as of December 31, 2014 and 2013, respectively is included in “Other current assets.”

Accounts Receivable

The amounts reported as “Accounts receivable, net” on our accompanying consolidated balance sheets as of December 31, 2014 and 2013 primarily consist of amounts due from customers.

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

Inventories

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

Gas Imbalances

We value gas imbalances due to or due from interconnecting pipelines at the lower of cost or market or index prices. As of December 31, 2014 and 2013, our gas imbalance receivables—including both trade and related party receivables—totaled $103 million and $83 million, respectively, and we included these amounts within “Other current assets” on our accompanying consolidated balance sheets. As of December 31, 2014 and 2013, our gas imbalance payables—consisting of only trade payables—totaled $36 million and $34 million, respectively, and we included these amounts within “Other current liabilities” on our accompanying consolidated balance sheets.

Property, Plant and Equipment

Capitalization, Depreciation and Depletion and Disposals

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

We generally compute depreciation using either the straight-line method based on estimated economic lives or, for certain depreciable assets, we employ the composite depreciation method, applying a single depreciation rate for a group of assets. Generally, we apply composite depreciation rates to functional groups of property having similar economic characteristics. The rates range from 0.9% to 23.0% excluding certain short-lived assets such as vehicles. For FERC-regulated entities, the FERC-

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accepted composite depreciation rate is applied to the total cost of the composite group until the net book value equals the salvage value. For other entities, depreciation estimates are based on various factors, including age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates included changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives (and salvage values where appropriate) that we believe are reasonable. Subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization expense. Historically, adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year.

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

We engage in enhanced recovery techniques in which CO_2 is injected into certain producing oil reservoirs. In some cases, the acquisition cost of the CO_2 associated with enhanced recovery is capitalized as part of our development costs when it is injected. The acquisition cost associated with pressure maintenance operations for reservoir management is expensed when it is injected. When CO_2 is recovered in conjunction with oil production, it is extracted and re-injected, and all of the associated costs are expensed as incurred. Proved developed reserves are used in computing units of production rates for drilling and development costs, and total proved reserves are used for depletion of leasehold costs. The units-of-production rate is determined by field.

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

Impairments

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

We evaluate our oil and gas producing properties for impairment of value on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure, using undiscounted future cash flows based on total proved and risk-adjusted probable and possible reserves. For the purpose of impairment testing, adjustments for the inclusion of risk-adjusted probable and possible reserves, as well as forward curve pricing, will cause impairment calculation cash flows to differ from the amounts presented in our supplemental information on oil and gas producing activities disclosed in "Supplemental Information on Oil and Gas Producing Activities (Unaudited)."

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

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Asset Retirement Obligations

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

Equity method of accounting

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

Goodwill

Goodwill represents the excess of the cost of an acquisition price over the fair value of the acquired net assets, and such amounts are reported separately on our consolidated balance sheets. As of December 31, 2014 and 2013 our total goodwill was $24,654 million and $24,504 million, respectively. Goodwill is not amortized, but instead is tested for impairment annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. We perform our goodwill impairment test on May 31 of each year. There were no impairment charges resulting from our May 31, 2014 or 2013 impairment testing, and no event indicating an impairment has occurred subsequent to May 31, 2014 other than as described below.

If a significant portion of one of our business segments is disposed of (that also constitutes a business), we allocate goodwill based on the relative fair values of the portion of the segment being disposed of and the portion of the segment remaining. During 2014, we recorded a $29 million write-down associated with a pending sale of certain terminals to a third-party, including $2 million of goodwill.

Revenue Recognition Policies

We recognize revenues as services are rendered or goods are delivered and, if applicable, title has passed. We recognize natural gas sales revenues and NGL sales revenue when the natural gas or NGL is sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectability of the revenue is reasonably assured. Our sales and purchases of natural gas and NGL are primarily accounted for on a gross basis as natural gas sales or product sales, as applicable, and cost of sales.

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

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

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

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

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

Environmental Matters

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

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

Pensions and Other Postretirement Benefits

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

Noncontrolling Interests

Noncontrolling interests represents the outstanding ownership interests in our consolidated subsidiaries that are not owned by us. In our accompanying consolidated income statements, the noncontrolling interest in the net income (or loss) of our consolidated subsidiaries is shown as an allocation of our consolidated net income and is presented separately as "Net income attributable to noncontrolling interests." In our accompanying consolidated balance sheets, noncontrolling interests represents the ownership interests in our consolidated subsidiaries' net assets held by parties other than us. It is presented separately as "Noncontrolling interests" within "Stockholders' Equity."

Income Taxes

Income tax expense is recorded based on an estimate of the effective tax rate in effect or to be in effect during the relevant periods. Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. Deferred tax assets are reduced by a valuation allowance for the amount of any tax benefit we do not expect to be realized.

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

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Foreign Currency Transactions and Translation

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

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

Comprehensive Income

For each of the years ended December 31, 2014, 2013 and 2012, the difference between our net income and our comprehensive income resulted from (i) unrealized gains or losses on derivative contracts accounted for as cash flow hedges; (ii) foreign currency translation adjustments; and (iii) unrealized gains or losses related to changes in pension and other postretirement benefit plan liabilities. For more information on our risk management activities, see Note 13.

Risk Management Activities

We utilize energy commodity derivative contracts for the purpose of mitigating our risk resulting from fluctuations in the market price of natural gas, NGL and crude oil. In addition, we enter into interest rate swap agreements for the purpose of hedging the interest rate risk associated with our debt obligations. We measure our derivative contracts at fair value and we report them on our balance sheet as either an asset or liability. If the derivative transaction qualifies for and is designated as a normal purchase and sale, it is exempted from fair value accounting and is accounted for using traditional accrual accounting.

Furthermore, changes in our derivative contracts' fair values are recognized currently in earnings unless hedge accounting is applied. If a derivative contract meets specific accounting criteria, the contract's gains and losses are allowed to offset related results on the hedged item in our income statement, and we may formally designate the derivative contract as a hedge and document and assess the effectiveness of the contract associated with the transaction that receives hedge accounting. Only designated qualifying items that are effectively offset by changes in fair value or cash flows during the term of the hedge are eligible to use the special accounting for hedging.

Our derivative contracts that hedge our energy commodity price risks involve our normal business activities, which include the purchase and sale of natural gas, NGL and crude oil, and we may designate these derivative contracts as cash flow hedges—derivative contracts that hedge exposure to variable cash flows of forecasted transactions—and the effective portion of these derivative contracts' gain or loss is initially reported as a component of other comprehensive income (outside earnings) and subsequently reclassified into earnings when the forecasted transactions affect earnings. The ineffective portion of the gain or loss is reported in earnings immediately.

Regulatory Assets and Liabilities

Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. We included the amounts of our regulatory assets and liabilities within "Other current assets," "Deferred charges and other assets," "Other current liabilities" and "Other long-term liabilities and deferred credits," respectively, in our accompanying consolidated balance sheets. As of December 31, 2014, the recovery period for these regulatory assets was approximately one year to forty-two years.

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The following table summarizes our regulatory asset and liability balances as of December 31, 2014 and 2013 (in millions):

	December 31,	
	2014	2013
Current regulatory assets	$81	$91
Non-current regulatory assets	406	446
Total regulatory assets	$487	$537
Current regulatory liabilities	$189	$135
Non-current regulatory liabilities	290	397
Total regulatory liabilities	$479	$532

On July 26, 2012, TGP filed an application with the FERC seeking authority to abandon by sale certain natural gas facilities located offshore in the Gulf of Mexico and onshore in the state of Louisiana, as well as a related offer of settlement that addressed the proposed rate and accounting treatment associated with the sale. The offer of settlement provided for a rate adjustment to TGP's maximum tariff rates upon the transfer of the assets and established a regulatory asset for a portion of the unrecovered net book value of the facilities to be sold. Effective September 1, 2013, following the FERC's approval of both the requested abandonment authorization and the offer of settlement, TGP sold these assets, and in 2013, TGP recognized both a $93 million increase in regulatory assets and a $36 million gain from the sale of assets.

Transfer of Net Assets Between Entities Under Common Control

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

Earnings per Share

For the years ended December 31, 2014 and 2013, earnings per share was calculated 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 do not participate in excess distributions over earnings.

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

	Year Ended December 31,	
	2014	2013
Class P	$1,015	$1,187
Participating securities(a)	11	6
Net Income Attributable to Kinder Morgan, Inc.	$1,026	$1,193

(a) Participating securities are unvested restricted stock awards issued to management employees that contain non-forfeitable rights to dividend equivalent payments.

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

	Year Ended December 31,	
	2014	2013
Unvested restricted stock awards	7	4
Outstanding warrants to purchase our Class P shares(a)	312	401
Convertible trust preferred securities	10	10

(a) Each of our warrants entitles the holder to purchase one share of our common stock for an exercise price of $40 per share, payable in cash or by cashless exercise, at any time until May 25, 2017.

On December 26, 2012, the remaining series of our Class A, Class B, and Class C shares were fully-converted and as a result, only our Class P common stock was outstanding as of December 31, 2012 (see Note 10).

For the year ended December 31, 2012, earnings per share was calculated using the two-class method. Earnings were allocated to each class of common stock based on the amount of dividends paid in the current period for each class of stock 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. For the investor retained stock, the allocation of undistributed earnings or excess distributions over earnings was in direct proportion to the maximum number of Class P shares into which it could convert.

For the Class P diluted earnings per share computations, total net income attributable to Kinder Morgan, Inc. was divided by the adjusted weighted-average shares outstanding during the period, including all potential common stock equivalents. This included, for the periods prior to December 26, 2012, the Class P shares into which the investor retained stock (collectively, our Class A, Class B and Class C common stocks) was convertible. The number of Class P shares on a fully-converted basis was the same before and after any conversion of our investor retained stock. Each time one Class P share was issued upon conversion of investor retained stock, the number of Class P shares went up by one, and the number of Class P shares into which the investor retained stock was convertible went down by one. Accordingly, there was no difference between Class P basic and diluted earnings per share because the conversion of Class A, Class B, and Class C shares into Class P shares did not impact the number of Class P shares on a fully-converted basis. Commencing with the acquisition of EP, potential common stock equivalents also included the Class P shares issuable in connection with the warrants and the trust preferred securities (see Note 10). As no securities were convertible into Class A shares, the basic and diluted earnings per share computations for Class A shares were the same. For the year ended December 31, 2012, the following potential Class P common stock equivalents were antidilutive and, accordingly, were excluded from the determination of diluted earnings per share; (i) 451 million related to outstanding warrants to purchase our Class P shares; and (ii) 11 million related to convertible trust preferred securities.

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The following tables set forth the computation of basic and diluted earnings per share from continuing operations for the year ending December 31, 2012 (in millions, except per share amounts):

	Year ended December 31, 2012 Income from Continuing Operations Available to Shareholders			
	Class P	Class A	Participating Securities(a)	Total
Income from continuing operations				$1,204
Less: income from continuing operations attributable to noncontrolling interests				(696)
Income from continuing operations attributable to KMI				508
Dividends paid in the period	$601	$542	$41	(1,184)
Excess distributions over earnings	(344)	(331)	(1)	$(676)
Income from continuing operations attributable to shareholders	$257	$211	$40	$508
Basic earnings per share from continuing operations				
Basic weighted-average number of shares outstanding	461	446	N/A	
Basic earnings per common share from continuing operations(b)	$0.56	$0.47	N/A	
Diluted earnings per share from continuing operations				
Income from continuing operations attributable to shareholders and assumed conversions(c)	$508	$211	N/A	
Diluted weighted-average number of shares	908	446	N/A	
Diluted earnings per common share from continuing operations(b)	$0.56	$0.47	N/A	

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The following tables set forth the computation of basic and diluted earnings per share for the year ended December 31, 2012 (in millions, except per share amounts):

	Year ended December 31, 2012 Net Income Available to Shareholders			
	Class P	Class A	Participating Securities(a)	Total
Net income attributable to KMI				$315
Dividends paid in the period	$601	$542	$41	(1,184)
Excess distributions over earnings	(441)	(426)	(2)	$(869)
Net income attributable to shareholders	$160	$116	$39	$315
Basic earnings per share				
Basic weighted-average number of shares outstanding	461	446	N/A	
Basic earnings per common share(b)	$0.35	$0.26	N/A	
Diluted earnings per share				
Net income attributable to shareholders and assumed conversions(c)	$315	$116	N/A	
Diluted weighted-average number of shares	908	446	N/A	
Diluted earnings per common share(b)	$0.35	$0.26	N/A	

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(a) Participating securities are unvested restricted stock awards issued to management employees that contain non-forfeitable rights to dividend equivalents payments.

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(b) The Class A shares earnings per share as compared to the Class P shares earnings per share were reduced due to the sharing of economic benefits (including dividends) amongst the Class A, B, and C shares. Class A, B and C shares owned by Richard Kinder, the sponsor investors, the original shareholders, and other management were referred to as "investor retained stock," and were convertible into a fixed number of Class P shares. In the aggregate, our investor retained stock was entitled to receive a dividend per share on a fully-converted basis equal to the dividend per share on our common stock. The conversion of shares of investor retained stock into Class P shares did not increase our total fully-converted shares outstanding, impact the aggregate dividends we paid or the dividends we paid per share on our Class P common stock.

(c) For the diluted earnings per share calculation, total net income attributable to each class of common stock was divided by the adjusted weighted-average shares outstanding during the period, including all potential common stock equivalents.

3. Acquisitions and Divestitures

Business Combinations and Acquisitions of Investments

During 2014, 2013 and 2012, we completed the following significant acquisitions accounted for in accordance with the "Business Combinations" Topic of the Codification.

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. Additionally, we adjust goodwill as a result of applying the look-through method of recording deferred taxes on the outside book tax basis differences in our investments without regard to non-tax deductible goodwill. We do not expect our recorded goodwill to be deductible for tax purposes.

The following table discloses our assignment of the purchase price for each of our significant acquisitions (in millions):

			Assignment of Purchase Price								
Ref.	Date	Acquisition	Purchase price	Current assets	Property plant & equipment	Deferred charges & other	Goodwill	Long-term debt	Other liabilities	Non-controlling interest	Previously held equity interest
(1)	11/14	Pennsylvania and Florida Jones Act Tankers	$270	$—	$ 270	$ 8	$ 25	$ —	$ (33)	$ —	$ —
(2)	1/14	American Petroleum Tankers and State Class Tankers	961	6	951	6	64	—	(66)	—	—
(3)	6/13	Goldsmith-Landreth Field Unit	280	—	298	—	—	—	(18)	—	—
(4)	5/13	Copano	3,733	218	2,788	1,973	963	(1,252)	(236)	(17)	(704)
(5)	5/12	EP	22,928	7,175	12,921	5,718	18,562	(13,417)	(4,234)	(3,797)	—

(1) Pennsylvania and Florida Jones Act Tankers

On November 5, 2014, we acquired two Jones Act tankers from Crowley Maritime Corporation (Crowley) for approximately $270 million. The table above includes an allocation of deferred taxes of $8 million as a decrease to "Goodwill" and an increase to "Deferred charges & other" for the portion of our outside basis difference associated with the underlying goodwill. "Other liabilities" includes (i) $8 million of contingent consideration and (ii) $25 million associated with unfavorable customer contracts representing the amount, on a present value basis, by which the customer contracts were below market day rates at the time of the acquisition. The unfavorable contracts liability is being amortized as a noncash adjustment to revenue over the remaining contract period. The MT Pennsylvania and the MT Florida engage in the marine transportation of crude oil, condensate and refined products in the U.S. domestic trade, commonly referred to as the Jones Act trade, and are currently operating pursuant to multi-year charters with a major integrated oil company. The vessels each have approximately 330 MBbl of cargo capacity and are included in the Terminals business segment. The acquired vessels will continue to be operated by Crowley.

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(2) American Petroleum Tankers and State Class Tankers

Effective January 17, 2014, we acquired APT and State Class Tankers (SCT) for aggregate consideration of $961 million in cash (the APT acquisition). The table above includes an allocation of deferred taxes of $6 million as a decrease to “Goodwill” and an increase to “Deferred charges & other” for the portion of our outside basis difference associated with the underlying goodwill. “Other liabilities” includes $61 million of unfavorable customer contracts representing the amount, on a present value basis, by which the customer contracts were below market day rates at the time of acquisition. This amount is being amortized as a noncash adjustment to revenue over the remaining contract period.

APT is engaged in Jones Act trade and its primary assets consist of a fleet of five medium range Jones Act qualified product tankers, each with 330 MBbl of cargo capacity, and each operating pursuant to long-term time charters with high quality counterparties, including major integrated oil companies, major refiners and the U.S. Military Sealift Command. As of the closing date, the vessels’ time charters had an average remaining term of approximately four years, with renewal options to extend the terms by an average of two years. APT’s vessels are operated by Crowley.

SCT has commissioned the construction of four medium range Jones Act qualified product tankers, each with 330 MBbl of cargo capacity. The SCT vessels are scheduled to be delivered in 2015 and 2016 and are being constructed by General Dynamics’ NASSCO shipyard. We expect to invest approximately $276 million, including capitalized interest, to complete the construction of these four SCT vessels, and upon delivery, the vessels will be operated pursuant to long-term time charters with a major integrated oil company. Each of the time charters has an initial term of five years, with renewal options to extend the term by up to three years. The APT acquisition complements and extends our existing crude oil and refined products transportation and storage business. We include the acquired assets as part of the Terminals business segment.

(3) Goldsmith Landreth Field Unit

On June 1, 2013, we acquired certain oil and gas properties, rights, and related assets in the Permian Basin of West Texas from Legado Resources LLC for an aggregate consideration of $298 million consisting of $280 million in cash and assumed liabilities of $18 million (including $12 million of long-term asset retirement obligations). The acquisition of the Goldsmith Landreth San Andres oil field unit includes more than 6,000 acres located in Ector County, Texas. The acquired oil field is in the early stages of CO_2 flood development and includes a residual oil zone along with a classic San Andres waterflood. As part of the transaction, we obtained a long-term supply contract for up to 150 MMcf/d of CO_2. The acquisition complemented our existing oil and gas producing assets in the Permian Basin, and we included the acquired assets as part of the CO_2 business segment.

(4) Copano

Effective May 1, 2013, we acquired all of Copano’s outstanding units for a total purchase price of approximately $5.2 billion (including assumed debt and all other assumed liabilities). The transaction was a 100% unit for unit transaction with an exchange ratio of 0.4563 of KMP’s common units for each Copano common unit. KMP issued 43,371,210 of its common units valued at $3,733 million as consideration for the Copano acquisition (based on the $86.08 closing market price of a common unit on the NYSE on the May 1, 2013 issuance date). Due to the fact that our acquisition included the remaining 50% interest in Eagle Ford Gathering LLC (Eagle Ford) that we did not already own, we remeasured the carrying value ($146 million) of our existing 50% equity investment in Eagle Ford to its fair value ($704 million) as of the May 1, 2013 acquisition date. As a result of this remeasurement, we recognized a $558 million non-cash gain and we reported this gain within “Gain on remeasurement of previously held equity investments to fair value” in our accompanying consolidated statement of income for the year ended December 31, 2013.

(5) EP

Effective on May 25, 2012, we acquired all of the outstanding shares of EP for an aggregate consideration of approximately $22.9 billion (excluding assumed debt, but including payments of $87 million for share based awards expensed in the post-combination period). In total, EP shareholders received (i) $11.6 billion in cash; (ii) 330 million KMI Class P shares with a fair value of $10.6 billion (based on the $32.11 closing market price of a Class P share on May 24, 2012); and (iii) 505 million KMI warrants with a fair value of $863 million (based on a fair value of $1.71 per warrant as of May 24, 2012). The warrants have an exercise price of $40 per share and a 5-year term.

During the year 2012, we incurred $463 million, net of legal recoveries, of pre-tax expenses associated with the EP acquisition, including (i) $160 million in employee severance, retention and bonus costs; (ii) $87 million of accelerated EP stock based compensation allocated to the post-combination period under applicable GAAP rules; (iii) $37 million in advisory

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fees; (iv) $68 million for legal fees and reserves, net of legal recoveries; (v) a $108 million write-off (due to debt repayments) or amortization of capitalized financing fees associated with the EP acquisition financing; and less (vi) a $29 million benefit associated with pension income.

Pro Forma Information

The following summarized unaudited pro forma consolidated income statement information for the years ended December 31, 2014 and 2013, assumes that the Crowley, APT, Copano and the Goldsmith Landreth field unit acquisitions had occurred as of January 1, 2013. We prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma financial results may not be indicative of the results that would have occurred if these acquisitions had been completed as of January 1, 2013 or the results that will be attained in the future. Amounts presented below are in millions, except for the per share amounts:

	Pro Forma Year Ended December 31,	
	2014	2013
	(Unaudited)	
Revenues	$16,260	$14,911
Income from continuing operations	2,448	2,665
Income from discontinued operations, net of tax	—	(4)
Net income	2,448	2,661
Net income attributable to noncontrolling interests	(1,419)	(1,490)
Net income attributable to Kinder Morgan, Inc.	1,029	1,171
Diluted earnings per common share		
Class P shares	$0.90	$1.12

Acquisitions Subsequent to December 31, 2014

On February 13, 2015, we acquired Hiland Partners, LP, a privately held Delaware limited partnership (Hiland) for an aggregate consideration of $3,058 million consisting of $1,715 million in cash and $1,343 million of assumed debt, of which approximately $368 million was immediately paid down after closing. The cash requirements associated with the acquisition were funded primarily from borrowings under a six-month bridge facility, discussed in Note 8 "Debt," and with proceeds from sales of our Class P shares issued under our equity distribution agreement. Hiland's assets consist primarily of crude oil gathering and transportation pipelines and gas gathering and processing systems, primarily serving production from the Bakken Formation in North Dakota and Montana.

On February 9, 2015, we announced the acquisition of three U.S. terminals and one undeveloped site from Royal Vopak for approximately $158 million. The acquisition covers (i) a 36-acre, 1,069,500-barrel storage complex at Galena Park, Texas that handles base oils, biodiesel and crude oil and is immediately adjacent to our Galena Park terminal complex; (ii) two terminals in North Carolina, one terminal in North Wilmington that handles chemicals and black oil and one terminal in South Wilmington that is not currently operating; and (iii) an undeveloped site at Perth Amboy, New Jersey, with waterfront access that can be developed. The transaction, subject to customary approvals, is expected to close during the first quarter of 2015.

Drop-down Assets

In periods prior to the Merger Transactions, we completed the following drop-down transactions to KMP and EPB.

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- Effective August 1, 2012, KMP acquired from us a 100% ownership interest in TGP and an initial 50% ownership interest in EPNG, referred to in this report as the August 2012 drop-down transaction;
- Effective March 1, 2013, KMP acquired from us the remaining 50% ownership interest it did not already own in both EPNG and the EP midstream assets (see “—KMP Previously Held Investment in El Paso Midstream Investment Company, LLC” following), referred to in this report as the March 2013 drop-down transaction; and
- On May 2, 2014, EPB acquired from us our 50% equity interest in Ruby Pipeline Holding Company, L.L.C. (Ruby), our indirect 50% equity interest in Gulf LNG Holdings Group, L.L.C. (Gulf LNG) and our indirect 47.5% equity interest in Young Gas Storage Company, Ltd., referred to in this report as the May 2014 drop-down transaction.

In this report, we refer to these acquisitions of assets by KMP from us as the drop-down transactions. These drop-down transactions were accounted for as transfers of net assets between entities under common control. Specifically, KMP reflected the acquired assets and assumed liabilities at our carrying value, including our EP purchase accounting adjustments as of May 25, 2012; however our consolidated financial statements were not affected.

KMP Previously Held Investment in El Paso Midstream Investment Company, LLC

Effective June 1, 2012, KMP acquired a 50% ownership interest in El Paso Midstream Investment Company, LLC (EP Midstream) for an aggregate consideration of $289 million in common units. EP Midstream is a joint venture that owns gas gathering, processing and treating assets located in the Uinta Basin in Utah and a natural gas and oil gathering system located in the Eagle Ford shale formation in South Texas, collectively referred to in this report as the EP midstream assets.

Since we owned the remaining 50% of the EP Midstream assets, we consolidated EP Midstream in the accompanying consolidated financial statements effective June 1, 2012. The operating results of the EP midstream assets are included in the Natural Gas Pipelines business segment. No gain or loss on the previously held equity investment was recognized as the fair value of the initial equity investment acquired through our EP acquisition was determined to equal the $289 million purchase price paid by KMP for its 50% interest. As such, the fair value of 100% of EP Midstream was determined to be $578 million.

We measured the identifiable intangible assets acquired at fair value on the acquisition date, and as a result, we recognized $50 million in “Deferred charges and other assets,” representing the fair value of separate and identifiable relationships with existing customers. We estimated the remaining useful life of these existing customer relationships to be approximately 10 years. After measuring all of the identifiable tangible and intangible assets acquired and liabilities assumed at fair value on the acquisition date, we recognized $248 million of “Goodwill.” We believe the primary item that generated the goodwill is our ability to grow the business by leveraging our pre-existing natural gas operations, and we believe that this value contributed to our acquisition price exceeding the fair value of acquired identifiable net assets and liabilities. This goodwill is not deductible for tax purposes.

Income Tax Impact of the Drop-Down of EP Assets to KMP

For income tax purposes, the March 2013 drop-down transaction was treated as a contribution and the August 2012 drop-down transaction was treated as a partial sale, and a partial contribution. As a result of the drop-down transactions, a deferred tax liability arose related to the portion of the outside basis difference associated with the underlying goodwill that was contributed to KMP by us. However, since the drop-downs were transactions between entities under common control, we recognized an offsetting deferred charge of $448 million for the August 2012 and $53 million for the March 2013 drop-down transactions. These balances were being amortized to income tax expense over the remaining useful lives of the transferred assets of approximately 25 years. For the years ended December 31, 2014 and 2013 and the period subsequent to the August 2012 drop-down through December 31, 2012, total income tax expense related to the amortization of the deferred charges was approximately $18 million, $20 million and $7 million, respectively. As a result of the tax impact of the Merger Transactions, the unamortized balance of the deferred charge of $456 million was reversed.

Divestitures

The FTC Natural Gas Pipelines Disposal Group – Discontinued Operations

Following our March 2012 agreement with the U.S. FTC to divest certain assets in order to receive regulatory approval for our EP acquisition, we began accounting for the FTC Natural Gas Pipelines disposal group as discontinued operations (prior to our sale announcement, we included the disposal group in the Natural Gas Pipelines business segment). The FTC Natural Gas Pipelines disposal group's assets consisted of some natural gas pipeline systems and a natural gas processing operation located in the rocky mountain region. Effective November 1, 2012, we sold the FTC Natural Gas Pipelines disposal group to Tallgrass Energy Partners, LP (now known as Tallgrass Development, LP) (Tallgrass), and we received proceeds of $1,791 million (before cash selling expenses) which we reported separately as "Proceeds from disposal of discontinued operations" within the investing section of our accompanying consolidated statement of cash flows for the year ended December 31, 2012. In November 2012, we also paid selling expenses of $78 million (consisting of certain required tax payments to joint venture partners).

Additionally, we recognized (i) a $4 million loss for the year ended December 31, 2013, for the true up of the final consideration and certain incremental selling expenses and (ii) a combined remeasurement loss of $937 million for the year ended December 31, 2012, to reflect our assessment of fair value of the disposal group's net assets as a result of the FTC

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mandated sale requirement. We reported these loss amounts separately as "Loss on sale and the remeasurement of the FTC Natural Gas Pipelines disposal group to fair value, net of tax" within the discontinued operations section of our consolidated statements of income for the years ended December 31, 2013 and 2012.

Summarized financial information for the FTC Natural Gas Pipelines disposal group is as follows (in millions):

	Year Ended December 31, 2012(a)
Operating revenues	$227
Operating expenses	(131)
Depreciation and amortization	(7)
Other expense	(1)
Earnings from equity investments	70
Interest income and Other, net	2
Income from operations of the FTC Natural Gas Pipelines disposal group	$160

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(a) 2012 amounts represent financial information for the ten month period ended October 31, 2012. We sold the FTC Natural Gas Pipelines disposal group effective November 1, 2012.

Express Pipeline System

Effective March 14, 2013, we sold both our one-third equity ownership interest in the Express pipeline system and our subordinated debenture investment in Express to Spectra Energy Corp. we received net cash proceeds of $402 million (after paying both a final working capital settlement and certain transaction related selling expenses), and we reported the net cash proceeds received from the sale separately as "Proceeds from sales of assets and investments" within the investing section of our accompanying consolidated statement of cash flows for the year ended December 31, 2013. Additionally, we recognized a combined $224 million pre-tax gain with respect to this sale, and we reported this gain amount separately as "Gain on sale of investments in Express pipeline system" on our accompanying consolidated statement of income for the year ended December 31, 2013. We also recorded an income tax expense of $84 million related to this gain on sale, and we included this expense within "Income Tax Expense." As of the date of sale, our equity investment in Express totaled $67 million and the note receivable due from Express totaled $110 million.

4. Income Taxes

The components of "Income from Continuing Operations Before Income Taxes" are as follows (in millions):

	Year Ended December 31,		
	2014	2013	2012
U.S.	$2,941	$3,107	$1,246
Foreign	150	331	97
Total Income from Continuing Operations Before Income Taxes	$3,091	$3,438	$1,343

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

	Year Ended December 31,		
	2014	2013	2012
Current tax expense			
Federal	$(16)	$57	$48
State	36	36	34
Foreign	13	9	10
Total	33	102	92
Deferred tax expense			
Federal	572	612	49
State	14	—	4
Foreign	29	28	(6)
Total	615	640	47
Total tax provision	$648	$742	$139

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

	Year Ended December 31,					
	2014		2013		2012	
Federal income tax	$1,082	35.0 %	$1,203	35.0 %	$470	35.0 %
Increase (decrease) as a result of:						
State deferred tax rate change	—	— %	(21)	(0.6)%	20	1.5 %
Taxes on foreign earnings	40	1.3 %	112	3.3 %	(6)	(0.5)%
Net effects of consolidating KMP's and EPB's U.S. income tax provision	(433)	(14.0)%	(488)	(14.2)%	(288)	(21.5)%
State income tax, net of federal benefit	37	1.2 %	45	1.3 %	21	1.6 %
Dividend received deduction	(50)	(1.6)%	(54)	(1.6)%	(32)	(2.4)%
Adjustments to uncertain tax positions	(5)	(0.2)%	(87)	(2.5)%	(72)	(5.3)%
Valuation allowance on Investment in NGPL	61	2.0 %	—	— %	—	— %
Disposition of certain international holdings	(112)	(3.6)%	—	— %	—	— %
Other	28	0.9 %	32	0.9 %	26	1.9 %
Total	$648	21.0 %	$742	21.6 %	$139	10.3 %

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

	December 31, 2014	2013
Deferred tax assets		
Employee benefits	$329	$238
Accrued expenses	123	136
Net operating loss, capital loss, tax credit carryforwards	778	673
Derivative instruments and interest rate and currency swaps	43	68
Debt fair value adjustment	102	112
Investments	4,858	—
Other	31	43
Valuation allowances	(154)	(95)
Total deferred tax assets	6,110	1,175
Deferred tax liabilities		
Property, plant and equipment	373	351
Investments	—	4,888
Other	30	20
Total deferred tax liabilities	403	5,259
Net deferred tax assets (liabilities)	$5,707	$(4,084)
Current deferred tax asset	$56	$567
Non-current deferred tax assets (liabilities)	5,651	(4,651)
Net deferred tax assets (liabilities)	$5,707	$(4,084)

Deferred Tax Assets and Valuation Allowances: As a result of the Merger Transactions, we acquired directly or indirectly all of the equity interests of KMP, KMR and EPB that we and our subsidiaries did not already own. In exchange for their interests in KMP and EPB, we paid stock and cash with a fair market value of approximately $64 billion to the limited partner unit holders. This represents a taxable exchange for which we received a step-up in tax basis in the underlying assets acquired (our investment in KMP and EPB). A deferred tax asset of approximately $10.3 billion related to the book tax basis difference in this investment has been recorded, computed as $64 billion tax basis in excess of $36 billion book basis at our statutory tax rate of 36.48%.

In accordance with ASC 810-10-45-23, if changes in a parent's ownership interest do not result in a change in its controlling financial interest in its subsidiary, those changes should be accounted for as equity transactions. No gain or loss is recognized in consolidated net income or comprehensive income. The carrying amount of the noncontrolling interest is adjusted to reflect the change in ownership interest in the subsidiary. Any difference between the fair value of the consideration received or paid and the amount by which the noncontrolling interest is adjusted is recognized in equity attributable to the parent. Therefore, because the transaction conforms to the conditions set forth in ASC 810-10-45-23, we have concluded that the increase in the deferred tax assets should be recorded with the offset to equity rather than the income statement.

The step-up in tax basis results in a deferred tax asset of approximately $4.9 billion primarily related to our investment in KMP and EPB. As book earnings from our investment in KMP and EPB are projected to exceed taxable income (primarily as a result of the partnership's tax depreciation in excess of book depreciation), the deferred tax asset related to our investment in KMP and EPB is expected to be fully realized.

We recorded a full valuation allowance of $61 million against the deferred tax asset related to our investment in NGPL as we no longer have viable means by which we reasonably expect to recover this asset.

We have deferred tax assets of $466 million related to net operating loss carryovers, $312 million related to alternative minimum and foreign tax credits, and $93 million of valuation allowances related to deferred tax assets at December 31, 2014. As of December 31, 2013, we had deferred tax assets of $354 million related to net operating loss carryovers, $11 million related to capital loss carryovers, $308 million related to alternative minimum and foreign tax credits, and valuation allowances

related to deferred tax assets of $95 million. We expect to generate taxable income beginning in 2016 and utilize all federal net operating loss carryforwards and alternative minimum tax carryforwards by the end of 2018.
Expiration Periods for Deferred Tax Assets: As of December 31, 2014, we have U.S. federal net operating loss carryforwards of $906 million, which will expire from 2018 - 2034; state losses of $1.9 billion which will expire from 2014 - 2034; and foreign losses of $213 million, of which approximately $124 million carries over indefinitely and $89 million expires from 2028 - 2035. We also have $300 million of federal alternative minimum tax credits which do not expire; and approximately $11 million of foreign tax credits, the majority of which will expire from 2016 - 2024. Use of our U.S. federal carryforwards is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation rules of Internal Revenue Service regulations.
Unrecognized Tax Benefits: We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based not only on the technical merits of the tax position based on tax law, but also the past administrative practices and precedents of the taxing authority. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate resolution.

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

	Year Ended December 31,		
	2014	2013	2012
Balance at beginning of period	$209	$269	$57
Uncertain tax positions of EP	—	4	289
Subtotal	209	273	346
Additions based on current year tax positions	12	11	11
Additions based on prior year tax positions	—	26	1
Reductions based on prior year tax positions	(3)	—	—
Reductions based on settlements with taxing authority	(24)	(86)	(55)
Reductions due to lapse in statute of limitations	(5)	(15)	(34)
Balance at end of period	$189	$209	$269

We recognize interest and/or penalties related to income tax matters in income tax expense. As of December 31, 2014, 2013, and 2012, we had $28 million, $29 million and $28 million of accrued interest and $2 million, $2 million and $2 million in accrued penalties, respectively. All of the $189 million of unrecognized tax benefits, if recognized, would affect our effective tax rate in future periods. In addition, we believe it is reasonably possible that our liability for unrecognized tax benefits will increase by approximately $1 million during the next year to approximately $190 million.

We are subject to taxation, and have tax years open to examination for the periods 2012-2013 in the U.S., 1999-2013 in various states and 2004-2013 in various foreign jurisdictions.

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5. Property, Plant and Equipment

Classes and Depreciation

As of December 31, 2014 and 2013, our property, plant and equipment consisted of the following (in millions):

	December 31,	
	2014	2013
Natural gas, liquids, crude oil and CO_2 pipelines	$18,119	$17,399
Natural gas, liquids, CO_2, and terminals station equipment	21,233	17,960
Natural gas, liquids (including linefill), and transmix processing	520	259
Other	3,964	3,656
Accumulated depreciation, depletion and amortization	(8,369)	(6,757)
	35,467	32,517
Land and land rights-of-way	1,324	1,158
Construction work in process	1,773	2,172
Property, plant and equipment, net	$38,564	$35,847

As of December 31, 2014 and 2013, property, plant and equipment included $15,026 million and $14,957 million, respectively, of assets which were regulated by either the FERC or the NEB. Depreciation, depletion, and amortization expense charged against property, plant and equipment was $1,862 million, $1,663 million, and $1,324 million for the years ended December 31, 2014, 2013, and 2012, respectively.

Asset Retirement Obligations

As of December 31, 2014 and 2013, we recognized asset retirement obligations in the aggregate amount of $192 million and $204 million, respectively, of which $7 million and $25 million , respectively, were classified as current. The majority of our asset retirement obligations are associated with our CO2 business segment, where we are required to plug and abandon oil and gas wells that have been removed from service and to remove the surface wellhead equipment and compressors.

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

Impairments

During 2014, continued deteriorating commodity prices for crude oil that is produced by the CO_2 segment's working interest in the Katz Strawn unit caused us to evaluate the carrying value of this oil producing field. The estimated fair value on these assets was based on the future discounted cash flows using the forward WTI crude oil price curve. We recognized a $235 million non-cash, pre-tax impairment charge to write-down this asset to its estimated fair value.

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6. Investments

Our investments primarily consist of equity investments where we hold significant influence over investee actions and which we account for under the equity method of accounting. As of December 31, 2014 and 2013 our investments consisted of the following (in millions):

	December 31,	
	2014	2013
Citrus Corporation	$1,805	$1,875
Ruby Pipeline Holding Company, L.L.C.	1,123	1,153
Midcontinent Express Pipeline LLC	748	602
Gulf LNG Holdings Group, LLC	547	578
EagleHawk	337	272
Plantation Pipe Line Company	303	307
Red Cedar Gathering Company	184	176
Double Eagle Pipeline LLC	150	144
Parkway Pipeline LLC	144	131
Fayetteville Express Pipeline LLC	130	144
Watco Companies, LLC	103	103
Fort Union Gas Gathering L.L.C.	70	161
Sierrita Pipeline LLC	63	19
Cortez Pipeline Company	17	12
All others	304	266
Total equity investments	6,028	5,943
Bond investments	8	8
Total investments	$6,036	$5,951

———

As shown in the table above, our significant equity investments, as of December 31, 2014 consisted of the following:

- Citrus Corporation—We own a 50% interest in Citrus Corporation, the sole owner of Florida Gas Transmission Company, L.L.C. (Florida Gas). Florida Gas transports natural gas to cogeneration facilities, electric utilities, independent power producers, municipal generators, and local distribution companies through a 5,300-mile natural gas pipeline. Energy Transfer Partners L.P. operates and owns the remaining 50% interest;
- Ruby Pipeline Holding Company, L.L.C.—We operate and own a 50% interest in Ruby Pipeline Holding Company, L.L.C., the sole owner of Ruby Pipeline natural gas transmission system. The remaining 50% interest is owned by a subsidiary of Veresen Inc. as convertible preferred interests;
- Midcontinent Express Pipeline LLC—We operate and own a 50% interest in MEP, the sole owner of the Midcontinent Express natural gas pipeline system. The remaining 50% ownership interest is owned by subsidiaries of Regency Energy Partners L.P.;
- Gulf LNG Holdings Group, LLC—We operate and own a 50% interest in Gulf LNG Holdings Group, LLC, the owner of a LNG receiving, storage and regasification terminal near Pascagoula, Mississippi, as well as pipeline facilities to deliver vaporized natural gas into third party pipelines for delivery into various markets around the country. The remaining 50% ownership interests are wholly and partially owned by subsidiaries of GE Financial Services and The Blackstone Group L.P.;
- BHP Billiton Petroleum (Eagle Ford Gathering) LLC, f/k/a EagleHawk Field Services LLC and referred to in this report as EagleHawk—We own a 25% interest in EagleHawk, the sole owner of natural gas and condensate gathering systems serving the producers of the Eagle Ford shale formation. A subsidiary of BHP Billiton operates EagleHawk and owns the remaining 75% ownership interest;

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- Plantation—We operate and own a 51.17% interest in Plantation, the sole owner of the Plantation refined petroleum products pipeline system. A subsidiary of Exxon Mobil Corporation owns the remaining interest. Each investor has an equal number of directors on Plantation's board of directors, and board approval is required for certain corporate actions that are considered substantive participating rights; therefore, we do not control Plantation, and account for the investment under the equity method;
- Red Cedar Gathering Company—We own a 49% interest in Red Cedar Gathering Company, the sole owner of the Red Cedar natural gas gathering, compression and treating system. The Southern Ute Indian Tribe owns the remaining 51% interest;
- Double Eagle Pipeline LLC - We owns a 50% equity interest in Double Eagle Pipeline LLC. The remaining 50% interest is owned by Magellan Midstream Partners;
- Parkway Pipeline LLC —We operate and own a 50% interest in Parkway Pipeline LLC, the sole owner of the Parkway Pipeline refined petroleum products pipeline system. Valero Energy Corp. owns the remaining 50% interest;
- Fayetteville Express Pipeline LLC —We own a 50% interest in FEP, the sole owner of the Fayetteville Express natural gas pipeline system. Energy Transfer Partners, L.P. owns the remaining 50% interest and serves as operator of Fayetteville Express Pipeline LLC;
- Watco Companies, LLC—We hold a preferred equity investment in Watco Companies, LLC, the largest privately held short line railroad company in the U.S. We own 100,000 Class A preferred shares and pursuant to the terms of the investment, receive priority, cumulative cash distributions from the preferred shares at a rate of 3.25% per quarter, and participates partially in additional profit distributions at a rate equal to 0.5%. The preferred shares have no conversion features and hold no voting powers, but do provide us certain approval rights, including the right to appoint one of the members to Watco's Board of Managers;
- Fort Union Gas Gathering LLC—We own a 37.04% equity interest in the Fort Union Gas Gathering LLC. Crestone Powder River LLC, a subsidiary of ONEOK Partners, owns 37.04%; WPX Energy Rocky Mountain, LLC owns 11.11%; and Western Gas Wyoming, LLC owns the remaining 14.81%. Western Gas Resources, Inc. serves as operator of Fort Union Gas Gathering LLC;
- Sierrita Pipeline LLC — We operate and own a 35% equity interest in the Sierrita Pipeline LLC. MGI Enterprises U.S. LLC, a subsidiary of PEMEX, owns 35%; and MIT Pipeline Investment Americas, Inc., a subsidiary of Mitsui & Co., Ltd, owns 30%;
- Cortez Pipeline Company—We operate and own a 50% interest in the Cortez Pipeline Company, the sole owner of the Cortez carbon dioxide pipeline system. A subsidiary of Exxon Mobil Corporation owns a 37% interest and Cortez Vickers Pipeline Company owns the remaining 13% interest; and
- NGPL Holdco LLC— We operate and own a 20% interest in NGPL Holdco LLC, the owner of NGPL and certain affiliates, collectively referred to in this report as NGPL, a major interstate natural gas pipeline and storage system.

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

	Year Ended December 31,		
	2014	2013	2012
Citrus Corporation(a)	$97	$84	$53
Fayetteville Express Pipeline LLC	55	55	55
Gulf LNG Holdings Group, LLC(a)	48	47	22
Midcontinent Express Pipeline LLC	45	40	42
Red Cedar Gathering Company	33	31	32
Plantation Pipe Line Company	29	35	32
Cortez Pipeline Company	25	24	25
Fort Union Gas Gathering L.L.C.(b)	16	11	—
Ruby Pipeline Holding Company, L.L.C.(a)	15	(6)	(5)
Watco Companies, LLC	13	13	13
Parkway Pipeline LLC	8	1	—
Sierrita Pipeline LLC	3	—	—
NGPL Holdco LLC(c)	—	(66)	(198)
Double Eagle Pipeline LLC(b)	(1)	1	—
EagleHawk	(7)	9	11
All others	27	48	71
Total	$406	$327	$153
Amortization of excess costs	$(45)	$(39)	$(23)

(a) 2012 amounts are for the period from May 25, 2012 through December 31, 2012.
(b) 2013 amounts are for the period from May 1, 2013 through December 31, 2013.
(c) 2013 and 2012 amounts include non-cash investment impairment charges, which we recorded in the amount of $65 million and $200 million (pre-tax), respectively.

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

	Year Ended December 31,		
Income Statement	2014	2013	2012
Revenues	$3,829	$3,615	$3,681
Costs and expenses	3,063	2,803	3,194
Net income (loss)	$766	$812	$487

	December 31,	
Balance Sheet	2014	2013
Current assets	$943	$950
Non-current assets	20,630	20,782
Current liabilities	1,643	1,451
Non-current liabilities	10,841	11,351
Partners'/owners' equity	9,089	8,930

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7. Goodwill and Other Intangibles

Goodwill and Excess Investment Cost

We record the excess of the cost of an acquisition price over the fair value of acquired net assets as an asset on our balance sheet. This amount is referred to and reported separately as "Goodwill" in our accompanying consolidated balance sheets. 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. During the quarter ended June 30, 2013, we created the Natural Gas Pipelines Non-Regulated reporting unit to include the non-regulated businesses we acquired from Copano on May 1, 2013 as well as other non-regulated businesses that were historically part of the former Natural Gas Pipelines reporting unit (now the Natural Gas Pipelines Regulated reporting unit). We then allocated goodwill between these two reporting units based on the relative fair values of the reporting units.

There were no impairment charges resulting from our May 31, 2014 impairment testing, and no event indicating an impairment has occurred subsequent to that date. We determined the fair value of each reporting unit as of May 31, 2014 based on a market approach utilizing an average dividend/distribution yield of comparable companies. The value of each reporting unit was determined on a stand-alone basis from the perspective of a market participant and represented the price estimated to be received in a sale of the unit as a whole in an orderly transaction between market participants at the measurement date.

Changes in the gross amounts of our goodwill and accumulated impairment losses for each of the years ended December 31, 2014 and 2013 are summarized as follows (in millions):

	Natural Gas Pipelines	CO2	Products Pipelines	Terminals	Kinder Morgan Canada	Total
Historical Goodwill	$22,276	$1,528	$2,129	$1,484	$626	$28,043
Accumulated impairment losses	(2,090)	—	(1,267)	(677)	(377)	(4,411)
Balance as of December 31, 2012	20,186	1,528	862	807	249	23,632
Acquisitions(a)	888	—	—	—	—	888
Currency translation adjustments	—	—	—	—	(16)	(16)
Balance as of December 31, 2013	21,074	1,528	862	807	233	24,504
Acquisitions(a)(b)	82	—	—	89	—	171
Currency translation adjustments	—	—	—	—	(19)	(19)
Impairment	—	—	—	(2)	—	(2)
Balance as of December 31, 2014	$21,156	$1,528	$862	$894	$214	$24,654

(a) 2014 and 2013 Natural Gas Pipelines acquisition amounts include $82 million and $881 million, respectively, relating to the May 1, 2013 Copano acquisition as discussed in Note 3. 2013 Natural Gas Pipelines acquisition amount also includes $7 million relating to other EP acquisition assets.

(b) 2014 Terminals acquisition amount includes $64 million related to the January 17, 2014 APT acquisition and $25 million related to the November 5, 2014 Crowley acquisition.

For more information on our accounting for goodwill, see Note 2.

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

The first differential, representing the excess of the fair market value of our investees' plant and other net assets over its underlying book value at either the date of acquisition or the date of the loss of control totaled $746 million and $809 million as of December 31, 2014 and 2013, respectively. In almost all instances, this differential, relating to the discrepancy between our share of the investee's recognized net assets at book values and at current fair values, represents our share of undervalued depreciable assets, and since those assets (other than land) are subject to depreciation, we amortize this portion of our investment cost against our share of investee earnings. As of December 31, 2014, this excess investment cost is being amortized over a weighted average life of approximately thirteen years.

The second differential, representing total unamortized excess cost over underlying fair value of net assets acquired (equity method goodwill) totaled $138 million as of both December 31, 2014 and 2013. This differential is not subject to amortization but rather to impairment testing. Accordingly, in addition to our annual impairment test of goodwill, we periodically reevaluate the amount at which we carry the excess of cost over fair value of net assets accounted for under the equity method, as well as the amortization period for such assets, to determine whether current events or circumstances warrant adjustments to our carrying value and/or revised estimates of useful lives. Our impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. As of December 31, 2014, we believed no such impairment had occurred and no reduction in estimated useful lives was warranted.

Other Intangibles

Excluding goodwill, our other intangible assets include customer contracts, relationships and agreements, lease value, and technology-based assets. As of December 31, 2014 and 2013, these intangible assets totaled $2,302 million and $2,438 million, respectively, and primarily consisted of customer contracts, relationships and agreements associated with our Natural Gas Pipelines and Terminals business segments.

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

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

For the years ended December 31, 2014, 2013 and 2012, the amortization expense on our intangibles totaled $143 million , $125 million and $86 million, respectively. Our estimated amortization expense for our intangible assets for each of the next five fiscal years (2015 – 2019) is approximately $142 million, $133 million, $129 million, $126 million, and $125 million , respectively. As of December 31, 2014, the weighted average amortization period for our intangible assets was approximately nineteen years.

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8. 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 using the effective interest rate method. 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 and premiums (in millions):

	December 31,	
	2014	2013
KMI and Subsidiaries		
Senior term loan facilities, variable rate, due May 24, 2015 and May 6, 2017(a)	$—	$1,528
Senior notes and debentures, 2.00% through 8.25%, due 2014 through 2098(b)(c)(d)	11,438	5,645
Credit facility due November 26, 2019(e)(f)	850	175
Commercial paper borrowings(e)(f)	386	—
KMP		
Senior notes, 2.65% through 9.00%, due 2014 through 2044(b)	17,800	15,600
Commercial paper borrowings(g)(h)	—	979
Credit facility due May 1, 2018(g)	—	—
TGP senior notes, 7.00% through 8.375%, due 2016 through 2037(b)	1,790	1,790
EPNG senior notes, 5.95% through 8.625%, due 2017 through 2032(b)	1,115	1,115
Copano senior notes, 7.125% due April 1, 2021(b)	332	332
EPB		
EPPOC senior notes, 4.10% through 7.50%, due 2015 through 2042(b)(i)	2,860	2,260
Credit facility due May 27, 2016(g)	—	—
CIG, senior notes, 5.95% through 6.85%, due 2015 through 2037(b)(j)	475	475
SLNG senior notes, 9.50% through 9.75%, due 2014 through 2016(b)(k)	—	135
SNG notes, 4.40% through 8.00%, due 2017 through 2032(b)(l)	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(b)	1,636	1,636
EPC Building, LLC, promissory note, 3.967%, due 2014 through 2035	453	461
Preferred securities, 4.75%, due March 31, 2028(d)(m)	280	280
KMGP, $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock(n)	100	100
Other miscellaneous debt(o)	303	494
Total debt – KMI and Subsidiaries	41,029	34,216
Less: Current portion of debt(p)	2,717	2,306
Total long-term debt – KMI and Subsidiaries(q)	$38,312	$31,910

(a) The senior secured term loan facility, due May 24, 2015, was repaid and replaced in May 2014 with a new unsecured senior term loan facility due May 6, 2017. The unsecured senior term loan facility was repaid in November 2014 (see "—Credit Facilities and Restrictive Covenants" below).

(b) Notes provide for the redemption at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date plus a make whole premium.

(c) Includes $6.0 billion of senior notes issued on November 26, 2014 as a result of the Merger Transactions (see "—Debt Issuances and Repayments" below).

(d) On June 30, 2014, El Paso Issuing Corporation, a wholly-owned subsidiary of El Paso Holdco LLC and the corporate co-issuer under certain guaranteed notes, merged with and into El Paso Holdco LLC, a wholly-owned subsidiary of KMI, and immediately thereafter, El Paso Holdco LLC merged with and into KMI pursuant to an internal restructuring transaction. KMI succeeded El Paso Holdco LLC as issuer with respect to these debt obligations. Consequently, El Paso Holdco LLC ceased to be an obligor with respect to approximately $3.6 billion of outstanding senior notes.

(e) As of December 31, 2014 and 2013, the weighted average interest rates on our credit facility borrowings, including commercial paper borrowings in 2014, were 1.54% and 2.67%, respectively.

(f) On November 26, 2014, we entered into a $4 billion replacement credit facility and a commercial paper program of up to $4 billion of unsecured notes (see "—Credit Facilities and Restrictive Covenants" below).

(g) On November 26, 2014, in conjunction with the Merger Transactions, KMP's and EPB's credit facility and KMP's commercial paper program were terminated.

(h) As of December 31, 2013, the average interest rate on KMP's outstanding commercial paper borrowings was 0.28%. The borrowings under KMP's commercial paper program were used principally to finance the acquisitions and capital expansions it made during 2014 and 2013.

(i) EPPOC's operating assets are its investments in WIC, CIG, SLNG, Elba Express, SNG, SLC, CPG, EP Ruby, LLC, Southern Gulf LNG Company, L.L.C. and CIG Gas Storage Company LLC. There are no significant restrictions on EPPOC's ability to access the net assets or cash flows related to its controlling interests in the operating companies either through dividend or loan. The restrictive covenants under these debt obligations are no more restrictive than the restrictive covenants under our credit facility. (See also “—Debt Issuances and Repayments” below.)

(j) CIG is subject to a number of restrictions and covenants under its debt obligation. The most restrictive of these include limitations on the incurrence of liens and limitations on sale-leaseback transactions.

(k) The SLNG senior notes were repaid on November 26, 2014.

(l) Under its indentures, SNG is subject to a number of restrictions and covenants. The most restrictive of these include limitations on the incurrence of liens. Southern Natural Issuing Corporation (SNIC) is a wholly owned finance subsidiary of SNG and is the co-issuer of certain of SNG’s outstanding debt securities. SNIC has no material assets, operations, revenues or cash flows other than those related to its service as a co-issuer of the debt securities. Accordingly, it has no ability to service obligations on the debt securities.

(m) Capital Trust I (Trust I), is a 100%-owned business trust that as of December 31, 2014, had $5.6 million of 4.75% trust convertible preferred securities outstanding (referred to as the EP Trust I Preferred Securities). Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4.75% convertible subordinated debentures, which are due 2028. Trust I’s sole source of income is interest earned on these debentures. This interest income is used to pay distributions on the preferred securities. We provide a full and unconditional guarantee of the EP Trust I Preferred Securities. There are no significant restrictions from these securities on our ability to obtain funds from our subsidiaries by distribution, dividend or loan. The EP Trust I Preferred Securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4.75%, carry a liquidation value of $50 per security plus accrued and unpaid distributions and are convertible at any time prior to the close of business on March 31, 2028, at the option of the holder, into the following mixed consideration: (i) 0.7197 of a share of our Class P common stock; (ii) $25.18 in cash without interest; and (iii) 1.100 warrants to purchase a share of our Class P common stock. We have the right to redeem these Trust I Preferred Securities at any time. Because of the substantive conversion rights of the securities into the mixed consideration, we bifurcated the fair value of the EP Trust I Preferred Securities into debt and equity components and as of December 31, 2014, the outstanding balance of $280 million (of which $141 million is classified as current) was bifurcated between debt ($248 million) and equity ($32 million). During the years ended December 31, 2014 and 2013, 3,923 and 107,618 EP Trust I Preferred Securities had been converted into (i) 2,820 and 77,442 shares of our Class P common stock; (ii) approximately $99,000 and $3 million in cash; and (iii) 4,315 and 118,377 in warrants, respectively.

(n) As of December 31, 2014, KMGP had outstanding 100,000 shares of its $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock due 2057. Since August 18, 2012, dividends on the preferred stock accumulate at a floating rate of the 3-month LIBOR plus 3.8975% and are payable quarterly in arrears, when and if declared by KMGP’s board of directors, on February 18, May 18, August 18 and November 18 of each year, beginning November 18, 2012. The preferred stock has approval rights over a commencement of or filing of voluntary bankruptcy by KMP or its SFPP or Calnev subsidiaries (see “—KMGP Preferred Shares” below).

(o) In conjunction with the construction of the Totem Gas Storage facility (Totem) and the High Plains pipeline (High Plains), CIG’s joint venture partner in WYCO funded 50% of the construction costs. EPB reflected the payments made by their joint venture partner as other long-term liabilities on the balance sheet during construction and upon project completion, the advances were converted into a financing obligation to WYCO. Upon placing these projects in service, EPB transferred its title in the projects to WYCO and leased the assets back. Although EPB transferred the title in these projects to WYCO, the transfer did not qualify for sale leaseback accounting because of EPB’s continuing involvement through its equity investment in WYCO. As such, the costs of the facilities remain on our balance sheets and the advanced payments received from EPB’s 50% joint venture partner were converted into a financing obligation due to WYCO. As of December 31, 2014, the principal amounts of the Totem and High Plains financing obligations were $73 million and $100 million, respectively, which will be paid in monthly installments through 2039 based on the initial lease term. At the expiration of the initial lease term, the lease agreement shall be extended automatically for the term of related firm service agreements. The interest rate on these obligations is 15.5%, payable on a monthly basis.

(p) Includes commercial paper borrowings.

(q) Excludes debt fair value adjustments. As of December 31, 2014 and December 31, 2013, our total “Debt fair value adjustments” increased our combined debt carrying amounts by $1,934 million and $1,977 million, respectively. In addition to all unamortized debt discount/premium amounts and purchase accounting on our debt balances, our debt fair value adjustments also include (i) amounts associated with the offsetting entry for hedged debt and (ii) any unamortized portion of proceeds received from the early termination of interest rate swap agreements. For further information about our debt fair value adjustments, see Note 13.

After the consummation of the Merger Transactions, KMI, KMP and EPB and substantially all of their respective wholly owned subsidiaries with debt entered into a cross guarantee agreement with respect to the existing debt of KMI, KMP, EPB and such subsidiaries, so that KMI and those subsidiaries are liable for the debt of KMI, KMP, EPB and such subsidiaries. Also, see Note 18.

Credit Facilities and Restrictive Covenants

On September 19, 2014, we entered into a new five-year $4.0 billion revolving credit agreement with a syndicate of lenders, which can be increased to $5.0 billion if certain conditions are met. The new revolving credit agreement was effective upon the closing of the Merger Transactions on November 26, 2014 and replaced the prior KMI credit agreement, the KMP credit agreement and the EPB credit agreement. On November 26, 2014, we entered into a $4.0 billion commercial paper program through the private placement of short-term notes. The notes mature up to 270 days from the date of issue and are not redeemable or subject to voluntary prepayment by us prior to maturity. The notes are sold at par value less a discount representing an interest factor or if interest bearing, at par. Borrowings under our revolving credit facility can be used for

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working capital and other general corporate purposes and as a backup to our commercial paper program. Similarly, our borrowings under our commercial paper program reduce the borrowings allowed under our credit facility.

Our credit facility borrowings bear interest at either (i) LIBOR plus an applicable margin ranging from 1.125% to 2.000% per annum based on our credit ratings or (ii) the greatest of (1) the Federal Funds Rate plus 0.5%; (2) the Prime Rate; and (3) LIBOR Rate for a one month eurodollar loan, plus 1%, plus, in each case, an applicable margin ranging from 0.125% to 1.00% per annum based on our credit rating. As of December 31, 2014, we were in compliance with all required financial covenants (described following).

Our credit facility included the following restrictive covenants as of December 31, 2014:

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

As of December 31, 2014, we had $850 million outstanding under our credit facility, $386 million outstanding under our commercial paper program and $223 million in letters of credit. Our availability under this facility as of December 31, 2014 was $2,541 million.

Subsequent Event

On February 4, 2015, in connection with the Hiland acquisition, we entered into and made borrowings of $1,641 million under a new six-month bridge credit facility with UBS AG, Stamford Branch. The credit facility bears interest at the same rate as our $4.0 billion revolving credit facility and the borrowing capacity is reduced by any payments made. As of the date of this filing, we had $1,516 million outstanding under this credit facility.

Copano Debt Acquired

As of the May 1, 2013 Copano acquisition date, KMP assumed the following outstanding Copano debt amounts (i) $404 million of outstanding borrowings under Copano’s revolving credit facility due June 10, 2016; (ii) $249 million aggregate principal amount of Copano’s 7.75% unsecured senior notes due June 1, 2018; and (iii) $510 million aggregate principal amount of Copano’s 7.125% unsecured senior notes due April 1, 2021.

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Debt Issuances and Repayments

Apart from the assumption of the Copano debt discussed above, following are significant long-term debt issuances and repayments made during 2014 and 2013:

	2014	2013
Issuances	$650 million senior term loan facility due 2017	$750 million 5.00% notes due 2021
	$500 million 2.00% notes due 2017(b)	$750 million 5.625% notes due 2023
	$1,500 million 3.05% notes due 2019(b)	$251 million EPC Building, LLC 3.967% promissory notes(a)
	$1,500 million 4.30% notes due 2025(b)	$600 million 3.50% notes due 2023
	$750 million 5.30% notes due 2034(b)	$700 million 5.00% notes due 2043
	$1,750 million 5.55% notes due 2045(b)	$800 million 2.65% notes due 2019
	$750 million 3.50% notes due 2021	$650 million 4.15% notes due 2024
	$750 million 5.50% notes due 2044	
	$650 million 4.25% notes due 2024	
	$550 million 5.40% notes due 2044	
	$600 million 4.30% notes due 2024	
Repayments	$500 million 5.125% notes due 2014	$500 million 5.00% notes due 2013
	$1,528 million senior term loan facility due 2015	$1,186 million senior term loan facility due 2015
	$650 million senior term loan facility due 2017(b)	$88 million 8.00% notes due 2013
	$207 million 6.875% notes due 2014	$249 million 7.75% notes due 2018(c)
		$178 million portion of 7.125% notes due 2021(d)

(a) In December 2012, our subsidiary, EPC Building, LLC had issued $468 million of 3.967% amortizing promissory notes with payments due 2013 through 2035, of which $217 million was issued to third parties and the remaining $251 million was held by KMI until they were sold to third parties in April of 2013.

(b) Debt issued or repaid associated with the Merger Transactions.

(c) KMP paid $259 million (based on a price of 103.875% of the principal amount) to fully redeem and retire the 7.75% series of senior notes in accordance with the terms and conditions of the indenture governing the notes.

(d) KMP paid $191 million for the partial redemption of the 7.125% senior notes.

KMGP Preferred Shares

The following table provides information about KMGP’s distributions on 100,000 shares of its Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock:

	Year Ended December 31,	
	2014	2013
Per share cash distribution declared for the period(a)	$41.860	$42.101
Per share cash distribution paid in the period	$41.877	$42.169

(a) On January 21, 2015, KMGP declared a distribution for the three months ended December 31, 2014, of $10.553 per share, which was paid on February 18, 2015 to shareholders of record as of February 2, 2015.

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Maturities of Debt

The scheduled maturities of the outstanding debt balances, excluding debt fair value adjustments as of December 31, 2014, are summarized as follows (in millions):

Year	Total
2015	$2,717
2016	1,684
2017	3,059
2018	2,328
2019	2,819
Thereafter	28,422
Total	$41,029

Interest Rates, Interest Rate Swaps and Contingent Debt

The weighted average interest rate on all of our borrowings was 5.02% during 2014 and 5.08% during 2013. Information on our interest rate swaps is contained in Note 13. For information about our contingent debt agreements, see Note 12.

Subsequent Event

Subsequent to December 31, 2014, additional EP Trust I Preferred Securities were converted, primarily consisting of 969,117 EP Trust I Preferred Securities converted on January 14, 2015, into (i) 697,473 of our Class P common stock; (ii) approximately $24 million in cash; and (iii) 1,066,028 in warrants.

9. Share-based Compensation and Employee Benefits

Share-based Compensation

Kinder Morgan, Inc.

Class P Shares

Stock Compensation Plan for Non-Employee Directors

We have a Stock Compensation Plan for Non-Employee Directors, in which our eligible non-employee directors participate. The plan recognizes that the compensation paid to each eligible non-employee director is fixed by our board, generally annually, and that the compensation is payable in cash. Pursuant to the plan, in lieu of receiving some or all of the cash compensation, each eligible non-employee director may elect to receive shares of Class P common stock. Each election will be generally at or around the first board meeting in January of each calendar year and will be effective for the entire calendar year. An eligible director may make a new election each calendar year. The total number of shares of Class P common stock authorized under the plan is 250,000. During 2014, 2013 and 2012, we made restricted Class P common stock grants to our non-employee directors of 6,210, 5,710 and 5,520, respectively. These grants were valued at time of issuance at $220,000, $210,000 and $185,000, respectively. All of the restricted stock grants made to non-employee directors vest during a six-month period.

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Restricted Stock and Long-term Incentive Retention Award Plan

Upon our initial public offering, our restricted stock compensation program replaced our Long-term Incentive Retention Award Plan (discussed below). Our restricted stock compensation program is available to employees eligible under the former Long-term Incentive Retention Award Plan. The following table sets forth a summary of activity and related balances of our restricted stock excluding that issued to non-employee directors (in millions, except share amounts):

	Year Ended December 31, 2014		Year Ended December 31, 2013		Year Ended December 31, 2012	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	6,382,885	$239	2,154,022	$69	1,163,090	$33
Granted	1,694,668	61	4,563,495	181	1,463,388	51
Vested	(460,032)	(14)	(83,444)	(3)	(102,033)	(3)
Forfeited	(244,227)	(9)	(251,188)	(8)	(370,423)	(12)
Outstanding at end of period	7,373,294	$277	6,382,885	$239	2,154,022	$69
Intrinsic value of restricted stock vested during the period		$17		$3		$4

Restricted stock grants made to employees have vesting periods ranging from 1 year with variable vesting dates to 10 years. Following is a summary of the future vesting of our outstanding restricted stock grants:

Year	Vesting of Restricted Shares
2015	713,675
2016	1,337,884
2017	1,653,507
2018	1,111,830
2019	1,720,568
2020	580,759
2021	199,725
2023	55,346
Total Outstanding	7,373,294

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

During 2014, 2013 and 2012, we recorded $57 million, $35 million and $14 million, respectively, in expense related to restricted stock grants. At December 31, 2014 and 2013, unrecognized restricted stock compensation expense, less estimated forfeitures, was approximately $170 million and $177 million, respectively.

From 2006 until our initial public offering, we elected not to make any restricted stock awards as a result of a 2007 going private transaction. To ensure that certain key employees who had previously received restricted stock and restricted stock unit awards continued under a long-term retention and incentive program, we implemented the Long-term Incentive Retention Award plan. The plan provided cash awards approved by our compensation committees which were granted in July of each year to recommended key employees. Senior management was not eligible for these awards. These grants required the employee to sign a grant agreement. The grants vested 100% after the third year anniversary of the grant provided the employee remained with us. The last grants made under this plan were made in July of 2010. During the years ended December 31, 2013 and 2012, we expensed $2 million and $7 million, respectively, related to these grants.

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Pension and Other Postretirement Benefit Plans

Overview of Retirement Benefit Plans

Savings Plan

We maintain a defined contribution plan covering eligible U.S. employees. We contribute 5% of eligible compensation for most of the plan participants. Certain plan participants' contributions and Company contributions are based on collective bargaining agreements. In connection with the EP acquisition, we assumed EP's defined contribution savings plan which was merged into our savings plan during 2012. In connection with the Copano acquisition, we assumed Copano's defined contribution savings plan which was merged into our savings plan during 2013. The total amount charged to expense for our savings plan was approximately $42 million, $40 million, and $32 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Pension Plans

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

Other Postretirement Benefit Plans

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

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

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Benefit Obligation, Plan Assets and Funded Status. The following table provides information about our pension and OPEB plans as of and for each of the years ended December 31, 2014 and 2013 (in millions):

	Pension Benefits		OPEB	
	2014	2013	2014	2013
Change in benefit obligation:				
Benefit obligation at beginning of period	$2,563	$2,792	$631	$720
Service cost	21	25	—	—
Interest cost	112	92	25	23
Actuarial loss (gain)	294	(132)	15	(38)
Benefits paid	(186)	(239)	(52)	(54)
Participant contributions	—	—	3	11
Medicare Part D subsidy receipts	—	—	2	6
Plan amendments	—	25	—	(37)
Benefit obligation at end of period	2,804	2,563	624	631
Change in plan assets:				
Fair value of plan assets at beginning of period	2,333	2,240	380	341
Actual return on plan assets	180	254	32	40
Employer contributions	50	78	26	42
Participant contributions	—	—	3	11
Benefits paid	(186)	(239)	(52)	(54)
Fair value of plan assets at end of period	2,377	2,333	389	380
Funded status - net liability at December 31,	$(427)	$(230)	$(235)	$(251)

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Components of Funded Status. The following table details the amounts recognized in our balance sheet at December 31, 2014 and 2013 related to our pension and OPEB plans (in millions):

	Pension Benefits		OPEB	
	2014	2013	2014	2013
Non-current benefit asset	$—	$—	$173	$224
Current benefit liability	—	—	(22)	(32)
Non-current benefit liability	(427)	(230)	(386)	(443)
Funded status - net liability at December 31,	$(427)	$(230)	$(235)	$(251)

Components of Accumulated Other Comprehensive Income (Loss). The following table details the amounts of pre-tax accumulated other comprehensive income (loss) at December 31, 2014 and 2013 related to our pension and OPEB plans which are included on our accompanying consolidated balance sheets, including the portion attributable to our noncontrolling interests, (in millions):

	Pension Benefits		OPEB	
	2014	2013	2014	2013
Unrecognized net actuarial loss	$(296)	$(10)	$(27)	$(17)
Unrecognized prior service (cost) credit	(4)	(5)	20	21
Accumulated other comprehensive (loss) income	$(300)	$(15)	$(7)	$4

We anticipate that approximately $2 million of pre-tax accumulated other comprehensive loss will be recognized as part of our net periodic benefit cost in 2015, including approximately $3 million of unrecognized net actuarial loss and approximately $1 million of unrecognized prior service credit.

Our accumulated benefit obligation for our pension plans was $2,719 million and $2,516 million at December 31, 2014 and 2013, respectively.
Our accumulated postretirement benefit obligation for our OPEB plans, whose accumulated postretirement benefit obligations exceeded the fair value of plan assets, was $553 million and $534 million at December 31, 2014 and 2013, respectively. The fair value of these plans' assets was approximately $145 million and $60 million at December 31, 2014 and 2013, respectively.
Plan Assets. The investment policies and strategies for the assets of each of the pension and OPEB plans are established by the Fiduciary Committee (the "Committee"), which is responsible for investment decisions and management oversight of each plan. The stated philosophy of the Committee is to manage these assets in a manner consistent with the purpose for which the plans were established and the time frame over which the plans' obligations need to be met. The objectives of the investment management program are to (1) meet or exceed plan actuarial earnings assumptions over the long term and (2) provide a reasonable return on assets within established risk tolerance guidelines and to maintain the liquidity needs of the plans with the goal of paying benefit and expense obligations when due. In seeking to meet these objectives, the Committee recognizes that prudent investing requires taking reasonable risks in order to raise the likelihood of achieving the targeted investment returns. In order to reduce portfolio risk and volatility, the Committee has adopted a strategy of using multiple asset classes.
As of December 31, 2014, the allowable range for target asset allocations in effect for the pension plan were 34% to 58%, equity, 40% to 50% fixed income, 0% to 5% cash, 0% to 2% alternative investments and 0% to 10% company securities (KMI Class P common stock). As of December 31, 2014, the target asset allocations in effect for the retiree medical and retiree life insurance plans were 70% equity and 30% fixed income.

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

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

- Level 2 assets' fair values are primarily based on pricing data representative of quoted prices for similar assets in active markets (or identical assets in less active markets). Included in this level are money market funds, common/collective trust funds, mutual funds, limited partnerships, trusts, fixed income and other securities. Money market funds are valued at amortized cost, which approximates fair value. The common/collective trust funds', mutual funds', limited partnerships' and trusts' fair values are based on the net asset value as reported by the issuer, which is determined based on the fair value of the underlying securities as of the valuation date. The fixed income securities' fair values are primarily based on an evaluated price which is based on a compilation of primarily observable market information or a broker quote in a non-active market.

- Level 3 assets' fair values are calculated using valuation techniques that require inputs that are both significant to the fair value measurement and are unobservable, or are similar to Level 2 assets and are also subject to certain restrictions associated with the timing of redemption which extend beyond 90 days as of December 31. Included in this level are insurance contracts, mutual funds with significant redemption restrictions, limited partnerships and private equity. Insurance contracts are valued at contract value, which approximates fair value. The mutual funds' fair values are primarily based on the net asset value as reported by the issuer, which is determined based on the fair value of the underlying securities as of the valuation date. The limited partnerships' and private equity investments' fair values are primarily based on the securities' value as reported by the issuer, which may be determined utilizing discounted present value.

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Listed below are the fair values of our pension and OPEB plans' assets that are recorded at fair value classified in each level at December 31, 2014 and 2013 (in millions):

	Pension Assets							
	2014				2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Cash and money market funds	$5	$91	$—	$96	$—	$20	$—	$20
Common/collective trusts(a)	—	863	—	863	—	920	—	920
Insurance contracts	—	—	15	15	—	—	15	15
Mutual funds(b)	71	198	—	269	92	134	—	226
Common and preferred stocks(c)	459	—	—	459	498	—	—	498
Corporate bonds	—	247	—	247	—	220	—	220
U.S. government securities	—	190	—	190	—	120	—	120
Asset backed securities	—	28	—	28	—	29	—	29
Limited partnerships	—	—	16	16	—	—	28	28
Equity trusts	—	199	—	199	—	235	—	235
Private equity	—	—	10	10	—	—	9	9
Other	—	(15)	—	(15)	—	13	—	13
Total asset fair value(c)	$535	$1,801	$41	$2,377	$590	$1,691	$52	$2,333

(a) For 2014, this category includes common/collective trust funds which are invested in approximately 47% fixed income and 53% equity. For 2013, this category includes common/collective trusts funds which are invested in approximately 36% fixed income, 62% equity and 2% short term securities.

(b) For 2014, this category includes mutual funds which are invested in approximately 74% fixed income and 26% equity. For 2013, this category includes mutual funds which are invested in approximately 60% fixed income, 40% equity and other investments.

(c) Plan assets include $252 million and $229 million of KMI Class P common stock for 2014 and 2013, respectively.

	OPEB Assets							
	2014				2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Cash and money market funds	$23	$—	$—	$23	$—	$—	$—	$—
Domestic equity securities	25	—	—	25	13	—	—	13
Common/collective trusts(a)	—	71	—	71	—	85	—	85
Fixed income trusts	—	63	—	63	65	—	—	65
Limited partnerships	76	79	—	155	92	72	—	164
Insurance contracts	—	—	49	49	—	—	46	46
Mutual funds	3	—	—	3	7	—	—	7
Total asset fair value	$127	$213	$49	$389	$177	$157	$46	$380

(a) For 2014, this category includes common/collective trust funds which are invested in approximately 67% equity and 33% fixed income securities. For 2013, this category includes common/collective trust funds which are invested in approximately 70% equity and 30% fixed income securities.

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The following tables present the changes in our pension and OPEB plans' assets included in Level 3 for the years ended December 31, 2014 and 2013 (in millions):

	Pension Assets				
	Balance at Beginning of Period	Transfers In (Out)	Realized and Unrealized Gains (Losses), net	Purchases (Sales), net	Balance at End of Period
2014					
Insurance contracts	$15	$—	$—	$—	$15
Limited partnerships	28	—	5	(17)	16
Private equity	9	—	2	(1)	10
Total	$52	$—	$7	$(18)	$41
2013					
Insurance contracts	$14	$—	$—	$1	$15
Mutual funds	40	—	—	(40)	—
Limited partnerships	24	—	3	1	28
Private equity	9	—	1	(1)	9
Total	$87	$—	$4	$(39)	$52

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	OPEB Assets				
	Balance at Beginning of Period	Transfers In (Out)	Realized and Unrealized Gains (Losses), net	Purchases (Sales), net	Balance at End of Period
2014					
Insurance contracts	$46	$—	$(3)	$6	$49
Total	$46	$—	$(3)	$6	$49
2013					
Insurance contracts	$44	$—	$—	$2	$46
Total	$44	$—	$—	$2	$46

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Changes in the underlying value of Level 3 assets due to the effect of changes of fair value were immaterial for the years ended December 31, 2014 and 2013.

Expected Payment of Future Benefits and Employer Contributions. As of December 31, 2014, we expect to make the following benefit payments under our plans (in millions):

Fiscal year	Pension Benefits	OPEB(a)
2015	$190	$46
2016	193	46
2017	193	45
2018	195	45
2019	195	44
2020-2024	965	209

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(a) Includes a reduction of approximately $2 million in each of the years 2015 - 2019 and approximately $12 million in aggregate for 2020 - 2024 for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

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In 2015, we expect to contribute $50 million to our pension plan and approximately $14 million, net of anticipated subsidies, to our OPEB plan.

Actuarial Assumptions and Sensitivity Analysis. Benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining our benefit obligation and net benefit costs of our pension and OPEB plans for 2014, 2013 and 2012:

	Pension Benefits			OPEB		
	2014	2013	2012	2014	2013	2012
Assumptions related to benefit obligations:						
Discount rate	3.66 %	4.45 %	3.40 %	3.56 %	4.34 %	3.34 %
Rate of compensation increase	4.50 %	3.50 %	3.00 %	n/a	n/a	n/a
Assumptions related to benefit costs:						
Discount rate(a)	4.45 %	3.40 %	4.22 %	4.34 %	3.62 %	4.11 %
Expected return on plan assets(b)(c)	7.50 %	8.00 %	8.44 %	7.43 %	7.35 %	8.21 %
Rate of compensation increase	3.50 %	3.00 %	3.50 %	n/a	n/a	n/a

(a) The discount rate related to pension benefit cost was 4.50% for the period from January 1, 2012 to May 24, 2012, and 4.03% for the period from May 25, 2012 to December 31, 2012 (the period subsequent to the EP acquisition). The discount rate related to other postretirement benefit cost was 3.34% for the period from January 1, 2013 to July 31, 2013 (the period prior to an OPEB plan amendment that resulted in a remeasurement) and 4.00% for the period from August 1, 2013 to December 31, 2013, and 4.25% for the period from January 1, 2012 to May 24, 2012 and 4.01% for the period from May 25, 2012 to December 31, 2012.

(b) The expected return on plan assets related to pension cost was 8.90% for the period from January 1, 2012 to May 24, 2012, and 8.11% for the period from May 25, 2012 to December 31, 2012 (the period subsequent to the EP acquisition). The expected return on plan assets related to other postretirement benefit cost was 8.90% for the period from January 1, 2012 to May 24, 2012, and 7.72% for the period from May 25, 2012 to December 31, 2012.

(c) The expected return on plan assets listed in the table above is a pre-tax rate of return based on our targeted portfolio of investments. For the assumed EP OPEB plans, we utilize an after-tax expected return on plan assets to determine our benefit costs, which is based on unrelated business income taxes at a rate of 21% and 24% for 2014 and 2013, respectively.

The expected long-term rates of return on plan assets were determined by combining a review of the historical returns realized within the portfolio, the investment strategy included in the plans' investment policy, and capital market projections for the asset classes in which the portfolio is invested and the target weightings of each asset class.

Actuarial estimates for our OPEB plans assumed a weighted-average annual rate of increase in the per capita cost of covered health care benefits of 7.00%, gradually decreasing to 4.50% by the year 2031. Assumed health care cost trends have a significant effect on the amounts reported for OPEB plans. A one-percentage point change in assumed health care cost trends would have the following effects as of December 31, 2014 and 2013 (in millions):

	2014	2013
One-percentage point increase:		
Aggregate of service cost and interest cost	$2	$2
Accumulated postretirement benefit obligation	47	45
One-percentage point decrease:		
Aggregate of service cost and interest cost	$(2)	$(1)
Accumulated postretirement benefit obligation	(40)	(39)

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Components of Net Benefit Cost and Other Amounts Recognized in Other Comprehensive Income. For each of the years ended December 31, the components of net benefit cost and other amounts (including amounts associated with the EP Pension and OPEB plans since the May 25, 2012 acquisition date) recognized in pre-tax other comprehensive income related to our pension and OPEB plans are as follows (in millions):

	Pension Benefits			OPEB		
	2014	2013	2012	2014	2013	2012
Components of net benefit cost:						
Service cost	$21	$25	$18	$—	$—	$—
Interest cost	112	92	67	25	23	18
Expected return on assets	(171)	(175)	(110)	(24)	(22)	(15)
Amortization of prior service (credit) cost	—	—	(1)	(2)	(1)	(1)
Amortization of net actuarial loss (gain)	—	—	10	(1)	3	4
Curtailment and settlement gain	—	(3)	(2)	—	—	(1)
Net benefit (credit) cost	(38)	(61)	(18)	(2)	3	5
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss:						
Net (gain) loss arising during period	285	(211)	85	10	(50)	25
Prior service cost (credit) arising during period	—	25	(17)	—	(18)	(4)
Amortization or settlement recognition of net actuarial gain (loss)	—	3	(10)	—	(3)	(5)
Amortization of prior service credit	—	—	1	1	1	1
Total recognized in total other comprehensive income loss	285	(183)	59	11	(70)	17
Total recognized in net benefit (credit) cost and other comprehensive (income) loss	$247	$(244)	$41	$9	$(67)	$22

Other Plans

Plans Associated with Foreign Operations

Two of our subsidiaries, Kinder Morgan Canada Inc. and Trans Mountain Pipeline Inc. (as general partner of Trans Mountain Pipeline L.P.) are sponsors of pension plans for eligible Trans Mountain pipeline system employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements (which provide pension benefits in excess of statutory limits) and defined contributory plans. These subsidiaries also provide postretirement benefits other than pensions for retired employees. Our combined net periodic benefit costs for these Trans Mountain pension and other postretirement benefit plans for the years ended December 31, 2014, 2013 and 2012 was $10 million, $11 million and $11 million, respectively, recognized ratably over each year. As of December 31, 2014, we estimate the overall net periodic pension and other postretirement benefit costs for these plans for the year 2015 will be approximately $14 million, although this estimate could change if there is a significant event, such as a plan amendment or a plan curtailment, which would require a remeasurement of liabilities. Furthermore, we expect to contribute approximately $11 million to these benefit plans in 2015.

Multiemployer Plans

As a result of acquiring several terminal operations, primarily the acquisition of Kinder Morgan Bulk Terminals, Inc. effective July 1, 1998, we participate in several multi-employer pension plans for the benefit of employees who are union members. We do not administer these plans and contribute to them in accordance with the provisions of negotiated labor contracts. Other benefits include a self-insured health and welfare insurance plan and an employee health plan where employees may contribute for their dependents' health care costs. Amounts charged to expense for these plans were approximately $13 million, $11 million and $11 million for the years ended December 31, 2014, 2013 and 2012, respectively. We consider the overall multi-employer pension plan liability exposure to be minimal in relation to the value of its total consolidated assets and net income.

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10. Stockholders' Equity

Kinder Morgan, Inc. – Equity Interests

Common Equity

During the years 2012 through 2014, as authorized by our board of directors under various repurchase programs, we repurchased shares and warrants. As of December 31, 2014, we had $2 million available for repurchases under the 2014 repurchase program. During the years ended December 31, 2014, 2013 and 2012, we paid a total of $98 million, $465 million and $157 million, respectively, for the repurchase of warrants. During the years ended December 31, 2014 and 2013, we repurchased $94 million and $172 million respectively, of our Class P shares.

The following table sets forth the changes in our outstanding shares:

	Class P	Class A	Class B	Class C
Balance at December 31, 2011	170,921,140	535,972,387	94,132,596	2,318,258
Shares issued for EP acquisition (see Note 3)	330,154,610	—	—	—
Shares issued with conversions of EP Trust I Preferred securities	562,521	—	—	—
Shares converted	535,972,387	(535,972,387)	(94,132,596)	(2,318,258)
Shares canceled	(2,049,615)	—	—	—
Restricted shares vested	107,553	—	—	—
Balance at December 31, 2012	1,035,668,596	—	—	—
Shares issued for EP acquisition(a)	53			
Shares repurchased and canceled	(5,175,055)			
Shares issued with conversions of EP Trust I Preferred securities	77,442			
Shares issued for exercised warrants	16,886			
Restricted shares vested	89,154			
Balance at December 31, 2013	1,030,677,076			
Shares issued for Merger Transactions	1,096,910,451			
Shares repurchased and canceled	(2,780,337)			
Shares issued with conversions of EP Trust I Preferred securities	2,820			
Shares issued for exercised warrants	12,402			
Restricted shares vested	324,704			
Balance at December 31, 2014	2,125,147,116			

(a) Represents Class P shares issued upon the settlement of an EP dissenter. The settlement of the dissenter's 128 EP shares was determined based on the same conversion of EP shares into cash, KMI Class P shares and KMI warrants that was received by other EP shareholders at the time of the acquisition.

As of January 1, 2012, the "Investors" (as defined hereinafter) owned all of our outstanding Class A shares, Class B shares and Class C shares, which are sometimes referred to in this report as the "investor retained stock." The Investors were Richard D. Kinder, our Chairman and Chief Executive Officer; the Sponsor Investors; Fayez Sarofim, one of our directors, and investment entities affiliated with him, and an investment entity affiliated with Michael C. Morgan, another of our directors and William V. Morgan, one of our founders, whom we refer to collectively as the "Original Stockholders"; and a number of other members of our management, who are referred to collectively as "Other Management." Our Class A shares represented the total capital contributed by the Investors (and a notional amount of capital allocated to the contribution of the holders of the Class C shares) at the time of a 2007 going private transaction. The Class B shares and Class C shares represented incentive compensation that were held by members of our management, including Mr. Kinder only in the case of the Class B shares.

During the year ended December 31, 2012, certain of the Sponsor Investors (the Selling Stockholders) completed underwritten public offerings (the Offerings) of an aggregate of 198,996,921 shares of our Class P common stock (including 8,700,000 shares that were the subject of an underwriters' option to purchase additional shares). Neither we nor our management sold any shares of common stock in the Offerings, and we did not receive any of the proceeds from the Offerings of shares by the Selling Stockholders. As a result of these offerings, the Sponsor Investors advised by or affiliated with

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Goldman Sachs & Co., The Carlyle Group, and Riverstone Holdings LLC no longer own any of our shares, and representatives of these Sponsor Investors are no longer on our board.

On December 26, 2012, the remaining series of the Class A, Class B and Class C shares held by the Investors automatically converted into shares of Class P common stock upon the election of the holders of at least two-thirds of the shares of each such series of Class A common stock and the holders of at least two-thirds of the shares of each such series of Class B common stock. Subsequent to these conversions, all our Class A, Class B and Class C shares were fully converted and as a result, only our Class P common stock was outstanding as of December 31, 2012. Additionally, as Class A, Class B and Class C shares converted, certain holders of Class P shares were paid out in cash and their Class P shares were immediately canceled. During the year ended December 31, 2012 approximately 2 million Class P shares were canceled resulting in payments totaling approximately $71 million to the holders of those shares.

Equity Issuances Subsequent to December 31, 2014

On December 19, 2014, we entered into an equity distribution agreement with UBS Securities LLC, referred to as UBS, with Citigroup Global Markets Inc., Credit Suisse Securities (U.S.A.) LLC, Deutsche Bank Securities Inc., J.P. Morgan Securities LLC and Mitsubishi UFJ Securities (U.S.A.), Inc. (each a “Manager” and, collectively, the “Managers”). We propose to issue and sell through or to the Managers, as sales agents and/or principals, shares of the our Class P common stock, par value $0.01 per share having an aggregate offering price of up to $5,000 million from time to time during the term of this Agreement. Subsequent to December 31, 2014, we had equity issuances of 20,363,204 shares of our Class P common stock.

Dividends

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

	Year Ended December 31,		
	2014	2013	2012
Per common share cash dividend declared for the period	$1.74	$1.60	$1.40
Per common share cash dividend paid in the period	1.70	1.56	1.34

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On January 21, 2015, our board of directors declared a cash dividend of $0.45 per share for the quarterly period ended December 31, 2014. This dividend was paid on February 17, 2015 to shareholders of record as of February 2, 2015. Since this dividend was declared after the end of the quarter, no amount is shown in our accompanying December 31, 2014 consolidated balance sheet as a dividend payable.

Warrants

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

	Warrants		
	2014	2013	2012
Beginning balance	347,933,107	439,809,442	—
Warrants issued in EP acquisition(a)	—	81	504,598,883
Warrants issued with conversions of EP Trust I Preferred securities(b)	4,315	118,377	859,796

Warrants exercised	(18,040)	(21,208)	—
Warrants repurchased and canceled	(49,783,406)	(91,973,585)	(65,649,237)
Ending balance	298,135,976	347,933,107	439,809,442

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(a) See Note 3. 2013 amount represents warrants issued upon the settlement of an EP dissenter. The settlement of the dissenter's 128 EP shares was determined based on the same conversion of EP shares into cash, KMI Class P shares and KMI warrants that was received by other EP shareholders at the time of the acquisition.

(b) See Note 8.

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Noncontrolling Interests

The caption “Noncontrolling interests” in our accompanying consolidated balance sheets consists of interests that we do not own in the following subsidiaries (in millions):

	December 31,	
	2014	2013
KMP	$—	$7,642
EPB	—	4,122
KMR	—	3,142
Other	350	286
	$350	$15,192

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At December 31, 2014, as a result of the Merger Transactions, we owned all of the outstanding common units of KMP and EPB and all of the outstanding shares of KMR that we or our subsidiaries did not already own.

At December 31, 2013, we owned, directly, and indirectly in the form of i-units corresponding to the number of shares of KMR we owned, approximately 43 million limited partner units of KMP. These units, which consisted of 22 million common units, 5 million Class B units and 16 million i-units, represented approximately 9.8% of the total outstanding limited partner interests of KMP. In addition, we indirectly own all the common equity of the general partner of KMP, which holds an effective 2% interest in KMP and its operating partnerships. Together, at December 31, 2013, our limited partner and general partner interests represented approximately 11.6% of KMP’s total equity interests and represented an approximate 50% economic interest in KMP. This difference resulted from the existence of incentive distribution rights (IDRs) previously held by KMGP, the general partner of KMP.

As of December 31, 2013, we owned approximately 90 million limited partner units of EPB, representing approximately 41% of the total equity interests of EPB. In addition, we were the sole owner of the general partner of EPB, which held an effective 2% interest in EPB.

At December 31, 2013, we owned approximately 16 million KMR shares representing approximately 13.0% of KMR’s outstanding shares.

Contributions

Prior to the completion of the Merger Transactions on November 26, 2014, contributions from our noncontrolling interests consisted primarily of equity issuances by KMP, EPB and KMR. Each of these subsidiaries had an equity distribution agreement in place which allowed the subsidiary to sell its equity interests from time to time through a designated sales agent. The terms of each agreement were substantially similar. Sales of the subsidiary’s equity interests were made by means of ordinary brokers’ transactions on the NYSE at market prices, in block transactions or as otherwise agreed between the subsidiary equity issuer and its sales agent. The subsidiary equity issuer could also sell its equity interests to its sales agent as principal for the sales agent’s own account at a price agreed upon at the time of the sale. Any sale of the subsidiary’s equity interests to the sales agent as principal would be pursuant to the terms of a separate agreement between the subsidiary equity issuer and its sales agent. The equity distribution agreement provided the subsidiary with the right, but not the obligation to offer and sell its equity units or shares, at prices to be determined by market conditions. The subsidiary retained at all times complete control over the amount and the timing of sales under its respective equity distribution agreement, and it designated the maximum number of equity units or shares to be sold through its sales agent, on a daily basis or otherwise as the subsidiary equity issuer and its sales agent agreed.

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The table below shows significant issuances to the public of common units or shares, the net proceeds from the issuances and the use of the proceeds during the years ended December 31, 2014 and 2013 by KMP, EPB and KMR (dollars in millions and shares in thousands):

	Issuances	Common units/shares (in thousands)	Net proceeds (in millions)		Use of proceeds
KMP					
Issued under Equity Distribution Agreement(a)					
	2014	5,513	$441		Reduced borrowings under KMP's commercial paper program
	2013	10,814	$900		Reduced borrowings under KMP's commercial paper program
Other issuances					
	February 2014	7,935	$603		Reduced borrowings under KMP's commercial paper program that were used to fund KMP's APT acquisition in January 2014
	February 2013	4,600	$385		Issued to pay a portion of the purchase price for the March 2013 drop-down transaction
	May 2013	43,371	$—	(b)	Issued to Copano unitholders as KMP's purchase price for Copano
EPB					
Issued under Equity Distribution Agreement(c)					
	2014	7,314	$275		General partnership purposes
	2013	2,038	$85		General partnership purposes
Other issuances					
	May 2014	7,820	$242		Issued to pay a portion of the purchase price for the May 2014 drop-down transaction
KMR					
Issued under Equity Distribution Agreement(d)					
	2014	1,735	$134		Purchased additional KMP i-units; KMP then used proceeds to reduce borrowings under its commercial paper program
	2013	2,640	$210		Purchased additional KMP i-units; KMP then used proceeds to reduce borrowings under its commercial paper program

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(a) Prior to the completion of the Merger Transactions on November 26, 2014, KMP was a party to two equity distribution agreements with UBS Securities LLC (UBS), one of which allowed the aggregate offering price of KMP's common units of up to $2.175 billion, and a second separate equity distribution agreement which allowed the aggregate offering price of up to $1.9 billion.

(b) KMP valued these units at $3,733 million based on the $86.08 closing market price of a KMP common unit on the NYSE on May 1, 2013.

(c) Prior to the completion of the Merger Transactions on November 26, 2014, EPB was a party to an equity distribution agreement with Citigroup. Pursuant to the provisions of EPB's equity distribution agreement, EPB could sell from time to time through Citigroup, as its sales agent, EPB's common units representing limited partner interests having an aggregate offering price of up to $500 million.

(d) Prior to the completion of the Merger Transactions on November 26, 2014, KMR was a party to an equity distribution agreement with Credit Suisse Securities (U.S.A.) LLC (Credit Suisse). Pursuant to the provisions of KMR's equity distribution agreement, it could sell from time to time through Credit Suisse, as its sales agent, KMR shares having an aggregate offering price of up to $500 million.

The above equity issuances by KMP, EPB and KMR during the periods ended November 25, 2014 and December 31, 2013 had the associated effects of increasing our (i) noncontrolling interests by $1,640 million and $5,059 million, respectively; (ii) accumulated deferred income taxes by $19 million and $93 million, respectively; and (iii) additional paid-in capital by $36 million and $161 million, respectively.

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Distributions

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

	Year Ended December 31,		
	2014	2013	2012
KMP(a)			
Per unit cash distribution declared for the period	$4.17	$5.33	$4.98
Per unit cash distribution paid in the period	$5.53	$5.26	$4.85
Cash distributions paid in the period to the public	$1,654	$1,372	$1,081
EPB(a)(b)			
Per unit cash distribution declared for the period	$1.95	$2.55	$1.74
Per unit cash distribution paid in the period	$2.60	$2.51	$1.13
Cash distributions paid in the period to the public	$347	$318	$137
KMR(a)(c)			
Share distributions paid in the period to the public	7,794,183	6,588,477	5,586,579

(a) As a result of the Merger Transactions, no distribution was declared for the fourth quarter of 2014.
(b) Represents distribution information since the May 2012 EP acquisition.
(c) KMR's distributions were paid in the form of additional shares or fractions thereof calculated by dividing the KMP cash distribution per common unit by the average of the market closing prices of a KMR share determined for a ten-trading day period ending on the trading day immediately prior to the ex-dividend date for the shares. Represents share distributions made in the period to noncontrolling interests and excludes 1,127,712, 976,723 and 902,367 of shares distributed in 2014, 2013 and 2012, respectively, on KMR shares we directly and indirectly owned.

11. Related Party Transactions

Affiliated Balances

The following table summarizes our balance sheet affiliate balances (in millions):

	December 31,	
	2014	2013
Balance sheet location		
Accounts receivable, net	$31	$19
Other current assets	3	3
Deferred charges and other assets	46	47
	$80	$69
Current portion of debt(a)	$6	$6
Accounts payable	22	9
Long-term debt(a)	172	169
	$200	$184

(a) Includes financing obligations payable to WYCO (See Note 8).

Notes Receivable

Plantation

We and ExxonMobil have a term loan agreement covering a note receivable due from Plantation. We own a 51.17% equity interest in Plantation and our proportionate share of the outstanding principal amount of the note receivable was $47 million and $48 million as of December 31, 2014 and 2013, respectively. The note bears interest at the rate of 4.25% per annum and provides for semiannual payments of principal and interest on December 31 and June 30 each year, with a final principal

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payment of $45 million (for our portion of the note) due on July 20, 2016. We included $1 million of the note receivable balance within “Other current assets” and we included the remaining outstanding balance within “Deferred charges and other assets” on our accompanying consolidated balance sheets as of both December 31, 2014 and 2013.

Gulf LNG Holdings Group, LLC

In conjunction with the acquisition of EP, KMI acquired a long-term note receivable, bearing interest at 12% per annum, that was due from Gulf LNG Holdings Group, LLC, a 50% equity investee, with a remaining principal amount of $85 million. Subsequent to the EP acquisition and through the end of 2012, we received payments on this note totaling $75 million. We received payments for the remaining note balance of $10 million during the first quarter of 2013.

Subsequent Event

MEP

On February 3, 2015 we renewed our loan agreement for an additional one-year term with MEP, our 50%-owned equity investee. The loan agreement allows us, at our sole option, to make loans from time to time to MEP to fund its working capital needs and for other LLC purposes. Each individual loan must be in an amount not less than $2 million, and the aggregate loan balance outstanding must not exceed $40 million. Borrowings under the loan agreement bear interest at a rate of one month LIBOR plus 1.75%, and all borrowings can be prepaid before maturity without penalty or premium. As of both December 31, 2014 and 2013 there was no amount outstanding pursuant to this loan agreement.

12. Commitments and Contingent Liabilities

Leases and Rights-of-Way Obligations

The table below depicts future gross minimum rental commitments under our operating leases and rights-of-way obligations as of December 31, 2014 (in millions):

Year	Commitment
2015	$97
2016	85
2017	75
2018	67
2019	65
Thereafter	289
Total minimum payments	$678

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The remaining terms on our operating leases, including probable elections to exercise renewal options, range from one to thirty-nine years. Total lease and rental expenses were $114 million, $126 million and $94 million for the years ended December 31, 2014, 2013 and 2012, respectively. The amount of capital leases included within “Property, plant and equipment, net” in our accompanying consolidated balance sheets as of December 31, 2014 and 2013 is not material to our consolidated balance sheets.

Commitments

Capital Contributions for Elba Liquefaction Project

In January 2013, SLC, our subsidiary, and Shell U.S. Gas and Power, LLC (Shell G&P), a subsidiary of Royal Dutch Shell plc (Shell), formed ELC, an equity method investment, to develop and own a natural gas liquefaction plant at SLNG's existing Elba Island LNG terminal. In connection with the formation of ELC, SLC and Shell G&P entered into a LLC agreement in which SLC owns 51% of ELC and Shell G&P owns the remaining membership interest. Under the terms of the LLC agreement, SLC and Shell G&P are both obligated to make certain capital contributions in proportion to their membership interests in ELC to fund the construction of the liquefaction facilities. Our investment at the terminal, including both the liquefaction facilities and SLNG ancillary facilities, is estimated to be approximately $1.3 billion.

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Contingent Debt

Our contingent debt disclosures pertain to certain types of guarantees or indemnifications we have made and cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote.

As of December 31, 2014 and 2013, our contingent debt obligations, as well as our obligations with respect to related letters of credit, totaled $1,069 million and $74 million, respectively. The December 31, 2014 amount is primarily represented by our proportional share of the debt obligations of two equity investees. Under such guarantees we are severally liable for our percentage ownership share of these equity investees' debt issued in the event of their non-performance. Also included in our contingent debt obligations is a guarantee of the debt obligations of our 50%-owned investee, Cortez Pipeline Company (we are severally liable for its percentage ownership share (50%) of the Cortez Pipeline Company debt and 100% of the debt issued by one of its subsidiaries in the event of their non-performance) which has a $200 million credit facility to fund an expansion project.

Guarantees and Indemnifications

We are involved in joint ventures and other ownership arrangements that sometimes require financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes and environmental matters.

Our potential exposure under guarantee and indemnification agreements can range from a specified to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Those arrangements with a specified dollar amount have a maximum stated value of approximately $688 million, which primarily represents indemnification agreements associated with EP's prior discontinued and foreign operations. We are unable to estimate a maximum exposure for our guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

13. 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 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.

As part of the EP acquisition, we acquired power forward and swap contracts. We have entered into offsetting positions that eliminate the price risks associated with our power contracts.
As of December 31, 2014, we discontinued hedge accounting on certain of our crude derivative contracts as we do not expect them to be highly effective, for accounting purposes, in offsetting the variability in cash flows. This was caused primarily by volatility in basis differentials. As the forecasted transactions are still probable, accumulated gains and losses remain in other comprehensive income until earnings are impacted by the forecasted transactions. Future changes in the derivative contracts' fair value subsequent to the discontinuance of hedge accounting will be reported in earnings. We may re-designate certain of these hedging relationships if their expected effectiveness improves.

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Energy Commodity Price Risk Management

As of December 31, 2014, we had entered into 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	(10.9	) MMBbl
Crude oil basis	(10.8	) MMBbl
Natural gas fixed price	(27.2	) Bcf
Natural gas basis	(8.0	) Bcf
Derivatives not designated as hedging contracts		
Crude oil fixed price	(14.9	) MMBbl
Natural gas fixed price	2.0	Bcf
Natural gas basis	6.5	Bcf
NGL fixed price	(2.1	) MMBbl

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As of December 31, 2014, 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 2017. We have additional economic hedge contracts through December 2018.

Interest Rate Risk Management

As of December 31, 2014 and 2013, we had a combined notional principal amount of $9,200 million and $5,400 million, respectively, of fixed-to-variable interest rate swap agreements, effectively converting the interest expense associated with certain series of senior notes from fixed rates to variable rates based on an interest rate of LIBOR plus a spread. All of our swap agreements have termination dates that correspond to the maturity dates of the related series of senior notes and, as of December 31, 2014, 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.

In February 2014, we entered into four separate fixed-to-variable interest rate swap agreements having a combined notional principal amount of $500 million. These agreements effectively convert a portion of the interest expense associated with our 3.50% senior notes due March 1, 2021, from a fixed rate to a variable rate. In September 2014, we entered into five separate fixed-to-variable interest rate swap agreements having a combined notional principal amount of $600 million. These agreements effectively convert a portion of the interest expense associated with our 4.25% senior notes due September 1, 2024, from a fixed rate to a variable rate. Additionally, in November 2014, we entered into twenty-one separate fixed-to-variable interest rate swap agreements having a combined notional principal amount of $3,000 million. These agreements effectively convert a portion of the interest expense associated with our 4.30% senior notes due June 1, 2025 and 3.05% senior notes due December 1, 2019, from a fixed rate to a variable rate.

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Fair Value of Derivative Contracts

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

Fair Value of Derivative Contracts

		Asset derivatives December 31,		Liability derivatives December 31,	
		2014	2013	2014	2013
	Balance sheet location	Fair value		Fair value	
Derivatives designated as hedging contracts					
Natural gas and crude derivative contracts	Other current assets/(Other current liabilities)	$309	$18	$(34)	$(33)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	6	58	—	(30)
Subtotal		315	76	(34)	(63)
Interest rate swap agreements	Other current assets/(Other current liabilities)	143	87	—	—
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	260	172	(53)	(116)
Subtotal		403	259	(53)	(116)
Total		718	335	(87)	(179)
Derivatives not designated as hedging contracts					
Natural gas, crude and NGL derivative contracts	Other current assets/(Other current liabilities)	73	4	(2)	(5)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	196	—	—	—
Subtotal		269	4	(2)	(5)
Power derivative contracts	Other current assets/(Other current liabilities)	10	7	(57)	(54)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	11	(16)	(73)
Subtotal		10	18	(73)	(127)
Total		279	22	(75)	(132)
Total derivatives		$997	$357	$(162)	$(311)

Debt Fair Value Adjustments

The offsetting entry to adjust the carrying value of the debt securities whose fair value was being hedged is included within “Debt fair value adjustments” on our accompanying consolidated balance sheets. Our “Debt fair value adjustments” also include all unamortized debt discount/premium amounts, purchase accounting on our debt balances, and any unamortized portion of proceeds received from the early termination of interest rate swap agreements. As of December 31, 2014 and 2013, these fair value adjustments to our debt balances included (i) $1,221 million and $1,379 million, respectively, associated with fair value adjustments to our debt previously recorded in purchase accounting; (ii) $347 million and $143 million, respectively, associated with the offsetting entry for hedged debt; (iii) $454 million and $517 million respectively, associated with unamortized premium from the termination of interest rate swap agreements; and offset by (iv) $88 million and $62 million, respectively, associated with unamortized debt discount amounts. As of December 31, 2014, the weighted-average amortization period of the unamortized premium from the termination of the interest rate swaps was approximately 16 years.

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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 of gain/(loss)recognized in income on derivatives	Amount of gain/(loss)recognized in income on derivatives and related hedged item		
		Year Ended December 31,		
		2014	2013	2012
Interest rate swap agreements	Interest expense	$207	$(425)	$55
Total		$207	$(425)	$55
Fixed rate debt	Interest expense	$(204)	$425	$(55)
Total		$(204)	$425	$(55)

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Derivatives in cash flow hedging relationships	Amount of gain/(loss) recognized in OCI on derivative (effective portion)(a)			Location of gain/(loss) reclassified from Accumulated OCI into income (effective portion)	Amount of gain/(loss) reclassified from Accumulated OCI into income (effective portion)(b)			Location of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Amount of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)		
	Year Ended December 31,				Year Ended December 31,				Year Ended December 31,		
	2014	2013	2012		2014	2013	2012		2014	2013	2012
Energy commodity derivative contracts	$423	$(45)	$87	Revenues—Natural gas sales	$(1)	$—	$4	Revenues—Natural gas sales	$—	$—	$—
				Revenues—Product sales and other	26	(13)	(15)	Revenues—Product sales and other	11	3	(11)
				Costs of sales	4	—	17	Costs of sales	—	—	—
Interest rate swap agreements	(15)	7	(5)	Interest expense	(4)	2	2	Interest expense	—	—	—
Total	$408	$(38)	$82	Total	$25	$(11)	$8	Total	$11	$3	$(11)

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(a) We expect to reclassify an approximate $208 million gain associated with energy commodity price risk management activities included in our accumulated other comprehensive loss balance as of December 31, 2014 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).

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Derivatives not designated as accounting hedges	Location of gain/(loss) recognized in income on derivatives	Amount of gain/(loss) recognized in income on derivatives		
		Year Ended December 31,		
		2014	2013	2012
Energy commodity derivative contracts	Revenues—Natural gas sales	$(7)	$—	$1
	Revenues—Product sales and other	20	(10)	(4)
	Costs of sales	—	2	—
	Other expense (income)	(2)	(2)	—
Total		$11	$(10)	$(3)

Credit Risks

We have counterparty credit risk as a result of our use of financial derivative contracts. Our counterparties consist primarily of financial institutions, major energy companies, natural gas and electric utilities and local distribution companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include (i) an evaluation of potential counterparties' financial condition (including credit ratings); (ii) collateral requirements under certain circumstances; and (iii) the use of standardized agreements which allow for netting of positive and negative exposure associated with a single counterparty. Based on our policies, exposure, credit and other reserves, our management does not anticipate a material adverse effect on our financial position, results of operations, or cash flows as a result of counterparty performance.

Our OTC swaps and options are entered into with counterparties outside central trading organizations such as futures, options or stock exchanges. These contracts are with a number of parties, all of which have investment grade credit ratings. While we enter into derivative transactions with investment grade counterparties and actively monitor their ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future.

In conjunction with the purchase of exchange-traded derivative contracts or when the market value of our derivative contracts with specific counterparties exceeds established limits, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of December 31, 2014 and 2013, we had $20 million and $167 million, respectively, of outstanding letters of credit supporting our commodity price risks associated with the sale of power.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring the posting of additional collateral upon a decrease in our credit rating. As of December 31, 2014, we estimate that if our credit rating was downgraded one or two notches, we would be required to post no additional collateral to our counterparties.

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Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

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 income/(loss)
Balance as of December 31, 2011	$(20)	$37	$(132)	$(115)
Other comprehensive income before reclassifications	32	14	(53)	(7)
Amounts reclassified from accumulated other comprehensive loss	(5)	—	9	4
Net current-period other comprehensive income	27	14	(44)	(3)
Balance as of December 31, 2012	7	51	(176)	(118)
Other comprehensive income before reclassifications	(14)	(49)	151	88
Amounts reclassified from accumulated other comprehensive loss	4	—	2	6
Net current-period other comprehensive income	(10)	(49)	153	94
Balance as of December 31, 2013	(3)	2	(23)	(24)
Other comprehensive income before reclassifications	254	(68)	(212)	(26)
Amounts reclassified from accumulated other comprehensive loss	(22)	—	(1)	(23)
Impact of Merger Transactions (See Note 1)	98	(42)	—	56
Net current-period other comprehensive income	330	(110)	(213)	7
Balance as of December 31, 2014	$327	$(108)	$(236)	$(17)

14. 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).

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Fair Value of Derivative Contracts

The following two tables summarize the fair value measurements of our (i) energy commodity derivative contracts and (ii) interest rate swap agreements, based on the three levels established by the Codification (in millions). Certain of our derivative contracts are subject to master netting agreements.

	Balance sheet asset fair value measurements using				Amounts not offset in the balance sheet		
	Level 1	Level 2	Level 3	Gross amount	Financial instruments	Cash collateral held(b)	Net amount
As of December 31, 2014							
Energy commodity derivative contracts(a)	$49	$533	$12	$594	$(46)	$(13)	$535
Interest rate swap agreements	$—	$403	$—	$403	$(44)	$—	$359
As of December 31, 2013							
Energy commodity derivative contracts(a)	$4	$46	$48	$98	$(62)	$—	$36
Interest rate swap agreements	$—	$259	$—	$259	$(28)	$—	$231

	Balance sheet liability fair value measurements using				Amounts not offset in the balance sheet		
	Level 1	Level 2	Level 3	Gross amount	Financial instruments	Cash collateral posted(c)	Net amount
As of December 31, 2014							
Energy commodity derivative contracts(a)	$(25)	$(11)	$(73)	$(109)	$46	$47	$(16)
Interest rate swap agreements	$—	$(53)	$—	$(53)	$44	$—	$(9)
As of December 31, 2013							
Energy commodity derivative contracts(a)	$(6)	$(31)	$(158)	$(195)	$62	$17	$(116)
Interest rate swap agreements	$—	$(116)	$—	$(116)	$28	$—	$(88)

(a) Level 1 consists primarily of NYMEX natural gas futures. Level 2 consists primarily of OTC WTI 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.

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

	Year Ended December 31,	
	2014	2013
Derivatives-net asset (liability)		
Beginning of period	$(110)	$(155)
Transfers out(a)	(88)	—
Total gains or (losses)		
Included in earnings	22	(5)
Included in other comprehensive loss	78	(1)
Purchases(b)	—	17
Settlements	37	34
End of period	$(61)	$(110)
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	$(8)

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(a) On December 31, 2014, we transferred WTI options from Level 3 to Level 2 due to increased observability of significant inputs in their valuations.
(b) 2013 amount represents the purchase of Level 3 energy commodity derivative contracts associated with our May 1, 2013 Copano acquisition.

As of December 31, 2014, our Level 3 derivative assets and liabilities consisted primarily of power derivative contracts, 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.

Fair Value of Financial Instruments

The estimated fair value of our outstanding debt balances (the carrying amounts below include both short-term and long-term and debt fair value adjustments), is disclosed below (in millions):

	December 31, 2014		December 31, 2013	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Total debt	$42,963	$43,582	$36,193	$36,248

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We used Level 2 input values to measure the estimated fair value of our outstanding debt balance as of both December 31, 2014 and 2013.

15. Reportable Segments

We divide our operations into the following reportable business segments. These segments and their principal sources of revenues are as follows:

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

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

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fields and gas processing plants in West Texas; and (iii) the ownership and operation of a crude oil pipeline system in West Texas;

- Terminals—(i) the ownership and/or operation of liquids and bulk terminal facilities and rail transloading and materials handling facilities located throughout the U.S. and portions of Canada that transload and store refined petroleum products, crude oil, condensate, and bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals and (ii) the ownership and operation of our Jones Act tankers;

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

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

- Other—primarily includes other miscellaneous assets and liabilities purchased in our 2012 EP acquisition including (i) our corporate headquarters in Houston, Texas; (ii) several physical natural gas contracts with power plants associated with EP's legacy trading activities; and (iii) other miscellaneous EP assets and liabilities.

We evaluate performance principally based on each segment's EBDA (including amortization of excess cost of equity investments), which excludes general and administrative expenses, third-party debt costs and interest expense, unallocable interest income, and unallocable income tax expense. Our reportable segments are strategic business units that offer different products and services, and they are structured based on how our chief operating decision makers organize their operations for optimal performance and resource allocation. Each segment is managed separately because each segment involves different products and marketing strategies.

We consider each period's earnings before all non-cash DD&A expenses to be an important measure of business segment performance for our reporting segments. We account for intersegment sales at market prices, while we account for asset transfers at either market value or, in some instances, book value.

During 2014, 2013 and 2012, we did not have revenues from any single external customer that exceeded 10% of our consolidated revenues.

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Financial information by segment follows (in millions):

	Year Ended December 31,		
	2014	2013	2012
Revenues			
Natural Gas Pipelines(a)			
Revenues from external customers	$10,153	$8,613	$5,230
Intersegment revenues	15	4	—
CO_2	1,960	1,857	1,677
Terminals			
Revenues from external customers	1,717	1,408	1,356
Intersegment revenues	1	2	3
Products Pipelines	2,068	1,853	1,370
Kinder Morgan Canada	291	302	311
Other	1	1	(6)
Total segment revenues	16,206	14,040	9,941
Other revenues(b)	36	36	35
Less: Total intersegment revenues	(16)	(6)	(3)
Total consolidated revenues	$16,226	$14,070	$9,973

	Year Ended December 31,		
	2014	2013	2012
Operating expenses(c)			
Natural Gas Pipelines(a)	$6,241	$5,235	$3,111
CO_2	494	439	381
Terminals	746	657	685
Products Pipelines	1,258	1,295	759
Kinder Morgan Canada	106	110	103
Other	24	30	5
Total segment operating expenses	8,869	7,766	5,044
Other operating expenses	—	—	4
Less: Total intersegment operating expenses	(16)	(6)	(3)
Total consolidated operating expenses	$8,853	$7,760	$5,045

	Year Ended December 31,		
	2014	2013	2012
Other expense (income)			
Natural Gas Pipelines(a)	$5	$(24)	$14
CO_2(d)	243	—	(7)
Terminals	29	(74)	(14)
Products Pipelines	(3)	6	(5)
Other	1	(7)	(1)
Total consolidated other expense (income)	$275	$(99)	$(13)

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	Year Ended December 31,		
	2014	2013	2012
DD&A			
Natural Gas Pipelines(a)	$897	$797	$478
CO_2	570	533	494
Terminals	337	247	236
Products Pipelines	166	155	143
Kinder Morgan Canada	51	54	56
Other	19	20	12
Total consolidated DD&A	$2,040	$1,806	$1,419

	Year Ended December 31,		
	2014	2013	2012
Earnings from equity investments			
Natural Gas Pipelines(a)(e)	$318	$232	$52
CO_2	25	24	25
Terminals	18	22	21
Products Pipelines	44	45	39
Kinder Morgan Canada	—	4	5
Other	1	—	11
Total consolidated equity earnings	$406	$327	$153

	Year Ended December 31,		
	2014	2013	2012
Amortization of excess cost of equity investments			
Natural Gas Pipelines(a)	$39	$32	$17
CO_2	(1)	2	2
Products Pipelines	7	5	4
Total consolidated amortization of excess cost of equity investments	$45	$39	$23

	Year Ended December 31,		
	2014	2013	2012
Interest income			
Natural Gas Pipelines	$1	$—	$18
Products Pipelines	2	2	2
Kinder Morgan Canada	—	3	14
Other	6	8	3
Total segment interest income	9	13	37
Unallocated interest income	—	2	(9)
Total consolidated interest income	$9	$15	$28

	Year Ended December 31,		
	2014	2013	2012
Other, net-income (expense)			
Natural Gas Pipelines(f)	$24	$578	$4
CO_2	—	—	(1)
Terminals	12	1	2
Products Pipelines	(1)	1	9
Kinder Morgan Canada(g)	15	246	3
Other	30	9	2
Total consolidated other, net-income (expense)	$80	$835	$19

	Year Ended December 31,		
	2014	2013	2012
Income tax benefit (expense)			
Natural Gas Pipelines	$(6)	$(9)	$(5)
CO_2	(8)	(7)	(5)
Terminals	(29)	(14)	(3)
Products Pipelines	(2)	2	2
Kinder Morgan Canada	(18)	(21)	(1)
Total segment income tax expense	(63)	(49)	(12)
Unallocated income tax expense	(585)	(693)	(127)
Total consolidated income tax expense	$(648)	$(742)	$(139)

	Year Ended December 31,		
	2014	2013	2012
Segment EBDA(h)			
Natural Gas Pipelines(a)	$4,259	$4,207	$2,174
CO_2	1,240	1,435	1,322
Terminals	944	836	708
Products Pipelines	856	602	668
Kinder Morgan Canada	182	424	229
Other	13	(5)	7
Total segment EBDA	7,494	7,499	5,108
Total segment DD&A	(2,040)	(1,806)	(1,419)
Total segment amortization of excess cost of equity investments	(45)	(39)	(23)
Other revenues	36	36	35
General and administrative expenses(i)	(610)	(613)	(929)
Interest expense, net of unallocable interest income(j)	(1,807)	(1,688)	(1,441)
Unallocable income tax expense	(585)	(693)	(127)
Loss from discontinued operations, net of tax(k)	—	(4)	(777)
Total consolidated net income	$2,443	$2,692	$427

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	Year Ended December 31,		
	2014	2013	2012
Capital expenditures			
Natural Gas Pipelines(a)	$935	$1,085	$499
CO_2	792	667	453
Terminals	1,049	1,108	707
Products Pipelines	680	416	307
Kinder Morgan Canada	156	77	16
Other	5	16	40
Total consolidated capital expenditures	$3,617	$3,369	$2,022

	2014	2013
Investments at December 31		
Natural Gas Pipelines(a)	5,174	$5,130
CO_2	17	12
Terminals	219	196
Products Pipelines	624	611
Kinder Morgan Canada	1	1
Other	1	1
Total consolidated investments	$6,036	$5,951

	2014	2013
Assets at December 31		
Natural Gas Pipelines	$52,523	$52,357
CO_2	5,227	4,708
Terminals	8,850	6,888
Products Pipelines	7,179	6,648
Kinder Morgan Canada	1,593	1,677
Other	459	568
Total segment assets	75,831	72,846
Corporate assets(l)	7,311	2,339
Assets held for sale	56	—
Total consolidated assets	$83,198	$75,185

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(a) The Copano acquisition was effective May 1, 2013 and the EP acquisition was effective May 25, 2012 (see Note 3).

(b) Includes a management fee for services we perform for NGPL Holdco LLC.

(c) Includes natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes.

(d) 2014 amount includes an impairment charge of $235 million primarily related to the Katz Strawn unit.

(e) 2013 and 2012 amounts include impairment charges of $65 million and $200 million, respectively, to reduce the carrying value of our equity investment in NGPL Holdco LLC.

(f) 2013 amount includes a $558 million gain from the remeasurement of our previously held 50% equity interest in Eagle Ford to fair value (See Note 3).

(g) 2013 amount includes a $224 million pre-tax gain from the sale of our equity and debt investments in the Express pipeline system (See Note 3).

(h)

Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income).

(i) 2012 amount includes $366 million of pre-tax expense associated with the EP acquisition and EP Energy sale.

(j) Includes (i) interest expense and (ii) miscellaneous other income and expenses not allocated to business segments. 2012 amount includes $108 million of expense for capitalized financing fees associated with the EP acquisition financing that were written-off (primarily due to debt repayments) or amortized.

(k) Represents loss from sale of the FTC Natural Gas Pipelines disposal group and other, net of tax (see Note 3).

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(l) Includes cash and cash equivalents, margin and restricted deposits, unallocable interest receivable, prepaid assets and deferred charges, 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.

We do not attribute interest and debt expense to any of our reportable business segments. For each of the years ended December 31, 2014, 2013 and 2012, we reported total consolidated interest expense of $1,807 million, $1,690 million, and $1,427 million, respectively.

Following is geographic information regarding the revenues and long-lived assets of our business segments (in millions):

	Year Ended December 31,		
	2014	2013	2012
Revenues from external customers			
U.S.	$15,605	$13,656	$9,488
Canada	437	398	407
Mexico	184	16	78
Total consolidated revenues from external customers	$16,226	$14,070	$9,973

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	2014	2013	2012
Long-lived assets at December 31(a)			
U.S.	$50,141	$42,080	$37,651
Canada	2,268	2,214	2,035
Mexico	81	81	82
Total consolidated long-lived assets	$52,490	$44,375	$39,768

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(a) Long-lived assets exclude goodwill and other intangibles, net.

16. 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 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, 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. 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 late June of 2014, certain shippers filed additional complaints with the FERC (docketed at OR14-35 and OR14-36) challenging SFPP's adjustments to its rates in 2012 and 2013 for inflation under the FERC's indexing regulations. 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 we may include in our rates. With respect to all of the SFPP proceedings at the FERC, we estimate that the shippers are seeking approximately $20 million in annual rate reductions and approximately $100 million in refunds. However, applying the principles of several recent FERC decisions in SFPP cases, as applicable, to pending cases would result in substantially lower rate reductions and refunds than those sought by the shippers. We do not expect refunds in these cases to have an impact on our dividends to our shareholders.

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) in May 2012. EPNG implemented certain aspects of that decision and believes it has an appropriate reserve related to the findings in Opinion 517. EPNG has sought rehearing on Opinion 517. With respect to the 2010 rate case, the FERC issued its decision (Opinion 528) on October 17, 2013. EPNG sought rehearing on certain issues in Opinion 528. As required by Opinion 528, EPNG filed revised pro forma recalculated rates consistent with the terms of Opinion 528. The FERC also required an Administrative Law Judge (ALJ) to conduct an additional hearing concerning one of the issues in Opinion 528. On September 17, 2014, the ALJ issued an initial decision finding certain shippers qualify for lower rates under a prior settlement. EPNG has sought FERC review of the ALJ decision and believes it has an appropriate reserve related to the findings in Opinion 528.

California Public Utilities Commission Proceedings

We have previously reported ratemaking and complaint proceedings against SFPP pending with the CPUC. The ratemaking and complaint cases generally involve challenges to rates charged by SFPP for intrastate transportation of refined petroleum products through its pipeline system in the state of California and request prospective rate adjustments and refunds with respect to tariffed and previously untariffed charges for certain pipeline transportation and related services.

On October 3, 2014, SFPP and its shippers executed a global settlement resolving all pending CPUC proceedings and submitted the proposed settlement to the CPUC for its consideration and approval. The settlement included refunds in the amount of $319 million, which was consistent with our established reserve amounts. It also included a three year moratorium on new rate filings or complaints and established current rates consistent with the revenues recognized by SFPP in 2014. On December 18, 2014, the CPUC issued its Decision No. 14-12-057 approving and adopting the global settlement, thereby resolving and closing all previously pending SFPP rate proceedings. On December 29, 2014, SFPP certified to the CPUC that it made all required settlement payments. Accordingly, SFPP filed with the CPUC a request to eliminate the previously imposed CPUC requirement that SFPP maintain a letter of credit in the amount of $100 million to secure SFPP's payment obligation for refunds related to the now-resolved CPUC rate proceedings. A decision from the CPUC is expected in the first quarter of 2015.

Other Commercial Matters

Union Pacific Railroad Company Easements

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. Judgment was entered by the Superior Court on May 29, 2012 and SFPP appealed the judgment.

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 rehearing with the Court of Appeals, which was denied on December 5, 2014. UPRR filed a petition for review to the California Supreme Court, which was denied on January 21, 2015. UPRR is expected to seek further appellate review by the U.S. Supreme Court. We believe we have recorded a right-of-way liability consistent with the Court of Appeals' decision and sufficient to cover our potential liability for back rent.

By notice dated October 25, 2013, UPRR demanded the payment of $22.25 million in rent for the first year of the next ten-year period beginning January 1, 2014. SFPP rejected the demand and the parties are pursuing the dispute resolution procedure in their contract to determine the rental adjustment, if any, for such period.

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SFPP and UPRR are also engaged in multiple disputes over the circumstances under which SFPP must pay for a relocation of its pipeline within the UPRR right-of-way and the safety standards that govern relocations. In July 2006, a trial before a judge regarding the circumstances under which SFPP must pay for relocations concluded, and the judge determined that SFPP must pay for any relocations resulting from any legitimate business purpose of the UPRR. SFPP appealed this decision, and in December 2008, the appellate court affirmed the decision. 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 is seeking declaratory relief with respect to its positions regarding the application of these standards with respect to relocations. A trial occurred in the fourth quarter of 2011, with a verdict having been reached that SFPP was obligated to comply with AREMA standards in connection with a railroad project in Beaumont Hills, California. On June 13, 2014, the trial court issued a statement of decision addressing all of the causes of action and defenses and resolved those matters against SFPP, consistent with the jury's verdict. The judgment was signed on July 15, 2014. SFPP filed a notice of appeal on October 30, 2014. If the judgment is affirmed on appeal, SFPP will be required to pay a judgment of $42.5 million plus any accrued post judgment interest.

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 expense (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.

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 and disputed its indemnity obligation. 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, 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 have been consolidated into one proceeding. 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 on the remaining claims. Trial was held in late 2014 and a decision is expected during the first half of 2015. Motions to dismiss have been filed in Brinckerhoff III and Brinckerhoff IV. Defendants continue to believe these lawsuits are without merit and intend to defend against them vigorously.

Allen v. El Paso Pipeline GP Company, L.L.C., et al.

In May 2012, a unitholder of EPB filed a purported class action in Delaware Chancery Court, alleging both derivative and non derivative claims, against EPB, and EPB's general partner and its board. EPB was named in the lawsuit as both a "Class Defendant" and a "Derivative Nominal Defendant." The complaint alleges a breach of the duty of good faith and fair dealing in connection with the March 2011 sale to EPB of a 25% ownership interest in SNG. On June 20, 2014, defendants' motion for summary judgment was granted, dismissing the case in its entirety. Plaintiff filed a notice of appeal to the Delaware Supreme Court, which will hear oral argument on February 25, 2015.

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Price Reporting Litigation

Beginning in 2003, several lawsuits were filed against El Paso Marketing L.P. (EPM) alleging that EP, EPM and other energy companies 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. A petition for certiorari was granted by the U.S. Supreme Court. Oral argument was heard on January 12, 2015 and the matter is stayed pending appeal. Although damages in excess of $140 million have been alleged in total against all defendants in one of the remaining lawsuits where a damage number is provided, there remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, that 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). The plaintiffs originally sought to enjoin one or more of the proposed Merger Transactions, which relief the Court denied on November 5, 2014. On December 12, 2014, the plaintiffs filed a Verified Second Consolidated Amended Class Action Complaint, which purports to assert claims on behalf of both the former EPB unitholders and the former KMP unitholders. The EPB plaintiff alleges 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 allege 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 seeks 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.

The defendants believe the allegations against them lack merit, and they intend to vigorously defend these lawsuits.

Kinder Morgan Energy Partners, L.P. Capex Litigation

Putative class action and derivative complaints were filed in the Court of Chancery in the State of Delaware against defendants KMI, KMGP and nominal defendant KMEP on February 5, 2014 and March 27, 2014 captioned Slotoroff v. Kinder Morgan, Inc., Kinder Morgan G.P., Inc. et al (Case No. 9318) and Burns et al v. Kinder Morgan, Inc., Kinder Morgan G.P., Inc. et al (Case No. 9479) respectively. The cases were consolidated on April 8, 2014 (Consolidated Case No. 9318). The consolidated suit seeks to assert claims both individually and on behalf of a putative class consisting of all public holders of KMEP units during the period of February 5, 2011 through the date of the filing of the complaints. The suit alleges direct and derivative causes of action for breach of the partnership agreement, breach of the duty of good faith and fair dealing, aiding and abetting, and tortious interference. Among other things, the suit alleges that defendants made a bad faith allocation of capital expenditures to expansion capital expenditures rather than maintenance capital expenditures for the alleged purpose of "artificially" inflating KMEP's distributions and growth rate. The suit seeks disgorgement of any distributions to KMGP, KMI and any related entities, beyond amounts that would have been distributed in accordance with a "good faith" allocation of maintenance capital expenses, together with other unspecified monetary damages including punitive damages and attorney fees. Defendants believe this suit is without merit and intend to defend it vigorously.

Walker v. Kinder Morgan, Inc., Kinder Morgan G.P., Inc. et al

On March 6, 2014, a putative class action and derivative complaint was filed in the District Court of Harris County, Texas (Case No. 2014-11872 in the 215th Judicial District) against KMI, KMGP, KMR, Richard D. Kinder, Steven J. Kean, Ted A. Gardner, Gary L. Hultquist, Perry M. Waughtal and nominal defendant KMEP. The suit was filed by Kenneth Walker, a purported unit holder of KMEP, and alleges derivative causes of action for alleged violation of duties owed under the

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partnership agreement, breach of the implied covenant of good faith and fair dealing, “abuse of control” and “gross mismanagement” in connection with the calculation of distributions and allocation of capital expenditures to expansion capital expenditures and maintenance capital expenditures. The suit seeks unspecified money damages, interest, punitive damages, attorney and expert fees, costs and expenses, unspecified equitable relief, and demands a trial by jury. Defendants believe this suit is without merit and intend to defend it vigorously. By agreement of the parties, the case is stayed pending further resolution of the Kinder Morgan Energy Partners, L.P. Capex Litigation described above.

Pipeline Integrity and Releases

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

General

As of December 31, 2014 and 2013, our total reserve for legal matters was $400 million and $624 million, respectively. The reserve primarily relates to various claims from regulatory proceedings arising from our products pipeline and natural gas pipeline transportation rates. The overall decrease in the reserve from December 31, 2013 was primarily due to the settlement refunds associated with our SFPP rate proceedings.

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. Once the EPA determines the cleanup remedy from the remedial investigations and feasibility studies conducted during the last decade at the site, it will issue a Record of Decision. Currently, KMLT and 90 other parties are involved in an allocation process to determine each party's respective share of the cleanup costs. This is a non-judicial allocation process. 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. We expect the allocation process to conclude in 2015. We also expect the LWG to complete the RI/FS process in 2015, after which the EPA is expected to develop a proposed plan leading to a Record of Decision targeted for 2017. We anticipate that the cleanup activities will begin within one year of the issuance of the Record of Decision.

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. Our motion to dismiss the suit was denied on August 19, 2014 and we have filed an answer to the Second Amended Complaint.

Paulsboro, New Jersey Liquids Terminal Consent Judgment

On June 25, 2007, the New Jersey Department of Environmental Protection (NJDEP) and the Administrator of the New Jersey Spill Compensation Fund, referred to collectively as the plaintiffs, filed a complaint in Gloucester County, New Jersey against ExxonMobil and KMLT, formerly known as GATX Terminals Corporation, alleging natural resource damages related to historic contamination at the Paulsboro, New Jersey liquids terminal owned by ExxonMobil from the mid-1950s through November 1989, by GATX Terminals Corporation from 1989 through September 2000, and later owned by Support Terminals and Pacific Atlantic Terminals, LLC. The terminal is now owned by Plains Products, which was also joined as a party to the lawsuit.

In mid 2011, KMLT and Plains Products entered into a settlement agreement and subsequent Consent Judgment with the NJDEP which resolved the state's alleged natural resource damages claim. The natural resource damage settlement includes a monetary award of $1 million and a series of remediation and restoration activities at the terminal site. KMLT and Plains Products have joint responsibility for this settlement. Simultaneously, KMLT and Plains Products entered into an agreement that settled each party's relative share of responsibility (50/50) to the NJDEP under the Consent Judgment noted above. The Consent Judgment is now entered with the Court and the settlement is final. According to the agreement, Plains will conduct remediation activities at the site and KMLT will provide oversight and 50% of the costs. We are awaiting approval from the NJDEP in order to begin remediation activities.

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 (Case No. 37-2007-00073033). On September 26, 2007, we removed the case to the U.S. District Court, Southern District of California (Case No. 07CV1883WCAB). The City disclosed in discovery that it is 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, which heard oral argument on February 3, 2015. The appeal remains pending.

This site has been, and currently is, under the regulatory oversight and order of the California Regional Water Quality Control Board (RWQCB). SFPP has completed the soil and groundwater remediation at the City of San Diego's stadium property site and conducted quarterly sampling and monitoring through 2014 as part of the compliance evaluation required by the RWQCB. SFPP's remediation effort is now focused on its adjacent Mission Valley Terminal site.

On May 7, 2013, the City of San Diego petitioned the California Superior Court for a writ of mandamus seeking an order setting aside the RWQCB's approval of an amendment to our permit request to increase the discharge of water from our groundwater treatment system to the City of San Diego's municipal storm sewer system. On October 10, 2014, the court ruled that the City's petition was moot and dismissed the case because the amendment to the permit was no longer required and had been rescinded by the RWQCB at the request of SFPP upon SFPP's completion of soil and groundwater remediation at the City's stadium property site.

Uranium Mines in Vicinity of Cameron, Arizona

In the 1950s and 1960s, Rare Metals Inc., a historical subsidiary of EPNG, operated 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 will conduct 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.

PHMSA Inspection of Carteret Terminal, Carteret, New Jersey

On April 4, 2013, the PHMSA, Office of Pipeline Safety issued a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order (NOPV) arising from an inspection at the KMLT, Carteret, New Jersey location on March 15, 2011 following a release and fire that occurred during maintenance activity on March 14, 2011. On July 17, 2013, KMLT entered into a Consent Agreement and Order with the PHMSA, pursuant to which KMLT paid a penalty of $63,100 and is required to complete ongoing pipeline integrity testing and other corrective measures by November 30, 2015.

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 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 under CERCLA based on prior ownership and/or operation of properties located along the relevant section of the Passaic River. EPEC Polymers and EPEC Oil Trust entered into two Administrative Orders on Consent (AOCs) which obligate them to investigate and characterize contamination at the Site. They are also part of a joint defense group of approximately 70 cooperating parties (CPG) which have entered into AOCs and are directing and funding the work required by the EPA. Under the first AOC, a remedial investigation and feasibility study of the Site is presently estimated to be completed by 2015.

Under the second AOC, the CPG members are conducting a CERCLA removal action at the Passaic River Mile 10.9, including the dredging of sediment in mud flats at this location of the river to a depth of two feet and installation of a cap. The dredging was completed in 2013 and capping work was completed in June 2014. 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. In its FFS, the EPA stated that it has identified over 100 industrial facilities as potentially responsible parties and it is likely that there are hundreds more private and public entities that could be named in any litigation concerning responsibility for the Site contamination.

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No final remedy for this portion of the Site will be selected until the public comment and response period for the FFS is completed and the Record of Decision (ROD) is issued by EPA, which is expected in September 2015. Until the ROD is issued there is uncertainty about what remedy will be implemented and the extent of potential costs. There is also uncertainty as to the impact of the RI/FS that the CPG is currently preparing for portions of the Site. Therefore, the scope of potential EPA claims for the lower eight miles of the Passaic River is not reasonably estimable at this time.

Southeast Louisiana Flood Protection Litigation

On July 24, 2013, the Board of Commissioners of the Southeast Louisiana Flood Protection Authority - East (SLFPA) filed a petition for damages and injunctive relief in state district court for Orleans Parish, Louisiana (Case No. 13-6911) against TGP, SNG and approximately 100 other energy companies, alleging that defendants' drilling, dredging, pipeline and industrial operations since the 1930's have caused direct land loss and increased erosion and submergence resulting in alleged increased storm surge risk, increased flood protection costs and unspecified damages to the plaintiff. The SLFPA asserts claims for negligence, strict liability, public nuisance, private nuisance, and breach of contract. Among other relief, the petition seeks unspecified monetary damages, attorney fees, interest, and injunctive relief in the form of abatement and restoration of the alleged coastal land loss including but not limited to backfilling and re-vegetation of canals, wetlands and reef creation, land bridge construction, hydrologic restoration, shoreline protection, structural protection, and bank stabilization. On August 13, 2013, the suit was removed to the U.S. District Court for the Eastern District of Louisiana. On September 10, 2013, the SLFPA filed a motion to remand the case to the state district court for Orleans Parish. The Court denied the remand motion on June 27, 2014. Louisiana Act 544 (the Act) went into effect on June 6, 2014 and specified the political entities authorized to institute litigation for environmental damage in the coastal zone. Under the Act, which was specifically made retroactive, we contend the SLFPA is not a valid plaintiff, whereas the SLFPA contends the Act is unconstitutional. The parties filed numerous cross motions seeking a ruling on the enforceability of the Act and other potentially dispositive legal issues. On February 13, 2015, the Court granted defendants' motion to dismiss the suit for failure to state a claim, and issued an order dismissing plaintiffs' claims with prejudice.

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. On December 18, 2013, defendants removed the case to the U.S. District Court for the Eastern District of Louisiana. On January 14, 2014, the plaintiff filed a motion to remand the case to state court. On August 11, 2014, the court entered an order suspending a ruling on the remand motion and administratively closing the case, pending a ruling on plaintiff's remand motion in another substantially similar case in the same federal court to which TGP is not a party. On December 1, 2014, the remand motion in the substantially similar case was granted. On February 3, 2015, TGP and other defendants filed a motion to re-open its case for the purpose of further proceedings, including the court's consideration of whether remand is required. 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 we await Kinetica’s response to TGP’s tender.

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Pennsylvania Department of Environmental Protection Notice of Alleged Violations

The Pennsylvania Department of Environmental Protection (PADEP) notified TGP of alleged violations of certain conditions to the construction permits issued to TGP for the construction of TGP's 300 Line Project in 2011. The alleged violations arise from field inspections performed by county conservation districts, as delegates of the PADEP, during construction. The PADEP alleges that TGP failed to implement and maintain best practices to achieve sufficient erosion and sediment controls, stabilization of the right-of-way, and prevention of potential discharge of sediment into the waters of the Commonwealth of Pennsylvania during construction, before placing the line into service, and in connection with the occurrence of 100 year storm events. On December 22, 2014, TGP entered into a consent order and agreement with the PADEP pursuant to which TGP agreed to pay a civil penalty of $210,000, $50,000 in costs, and $540,000 to fund community environmental programs in Pike, Potter, Susquehanna, and Wayne counties in Pennsylvania to generally improve water quality in such counties and help restore third party dump sites unrelated to TGP's construction or other activities.

General

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note, and other matters to which we and our subsidiaries are a party, will not have a material adverse effect on our business, financial position, results of operations or cash flows. As of December 31, 2014 and 2013, we have accrued a total reserve for environmental liabilities in the amount of $340 million and $378 million, respectively. In addition, as of both December 31, 2014 and 2013, we have recorded a receivable of $14 million, for expected cost recoveries that have been deemed probable.

17. Recent Accounting Pronouncements

Accounting Standards Updates

On May 28, 2014, the FASB issued ASU No. 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 U.S. public companies for annual reporting periods beginning after December 15, 2016, including interim reporting periods (January 1, 2017 for us). Early adoption is not permitted. We are currently reviewing the effect of ASU No. 2014-09 on our revenue recognition.

18. Guarantee of Securities of Subsidiaries

KMI, along with its direct and indirect subsidiaries KMP, EPB and Copano, are issuers of certain public debt securities. After the completion of the Merger Transactions, KMI and substantially all of its wholly owned domestic subsidiaries, including KMP, Copano and EPB, 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 Non-Guarantor Subsidiaries, 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, Copano or EPB 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 December 31, 2014, Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, Subsidiary Issuer and Guarantor-Copano, Subsidiary Issuer and Guarantor-EPB and Subsidiary Guarantors had $12,674 million, $17,800 million, $332 million, $2,860 million and $6,463 million of Guaranteed Notes outstanding, respectively. Included in the Subsidiary Guarantors debt balance as presented in the accompanying December 31, 2014 condensed

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consolidating balance sheet is approximately $178 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 Issuer and Guarantor-EPB, 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 Non-Guarantor Subsidiaries. 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 November 26, 2014, the KMI Transactions close date, KMR was dissolved and its assets merged into KMI. Therefore, for all periods presented KMR's financial statement balances and activities are reflected within the Parent Issuer and Guarantor column.

On January 1, 2015, EPB and its subsidiary, EPPOC merged with and into KMP and were dissolved. As a result of such merger, all of the subsidiaries of EPPOC are wholly owned subsidiaries of KMP and effective January 1, 2015, EPPOC is no longer a Subsidiary Issuer and Guarantor.

Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2014
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Issuer and Guarantor - EPB	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 36	$ —	$ —	$ —	$ 14,310	$ 1,886	$ (6)	$ 16,226
Operating costs, expenses and other								
Costs of sales	—	—	—	—	5,737	499	42	6,278
Depreciation, depletion and amortization	21	—	—	—	1,655	364	—	2,040
Other operating expenses	30	—	32	5	2,927	514	(48)	3,460
Total operating costs, expenses and other	51	—	32	5	10,319	1,377	(6)	11,778
Operating (loss) income	(15)	—	(32)	(5)	3,991	509	—	4,448
Other income (expense)								
Earnings from consolidated subsidiaries	1,948	3,235	224	742	2,259	1,120	(9,528)	—
Earnings from equity investments	—	—	—	—	407	(1)	—	406
Interest, net	(493)	41	(46)	(171)	(1,040)	(89)	—	(1,798)
Amortization of excess cost of equity investments and other, net	—	—	—	—	(13)	48	—	35
Income from continuing operations before income taxes	1,440	3,276	146	566	5,604	1,587	(9,528)	3,091
Income tax expense	(166)	(7)	—	—	(183)	(292)	—	(648)
Net income	1,274	3,269	146	566	5,421	1,295	(9,528)	2,443
Net income attributable to noncontrolling interests	(248)	—	—	—	(211)	—	(958)	(1,417)
Net income attributable to controlling interests	$ 1,026	$ 3,269	$ 146	$ 566	$ 5,210	$ 1,295	$ (10,486)	$ 1,026
Net Income	$ 1,274	$ 3,269	$ 146	$ 566	$ 5,421	$ 1,295	$ (9,528)	$ 2,443
Total other comprehensive (loss) income	(24)	287	—	(10)	386	(168)	(451)	20

Comprehensive income	1,250	3,556	146	556	5,807	1,127	(9,979)	2,463
Comprehensive income attributable to noncontrolling interests	(273)	—	—	—	(203)	—	(1,010)	(1,486)
Comprehensive income attributable to controlling interests	$ 977	$ 3,556	$ 146	$ 556	$ 5,604	$ 1,127	$ (10,989)	$ 977

Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2013
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Issuer and Guarantor - EPB	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 36	$ —	$ —	$ —	$ 12,511	$ 1,512	$ 11	$ 14,070
Operating costs, expenses and other								
Costs of sales	—	—	—	—	4,739	468	46	5,253
Depreciation, depletion and amortization	20	—	—	—	1,466	320	—	1,806
Other operating expenses	22	—	38	8	2,325	663	(35)	3,021
Total operating costs, expenses and other	42	—	38	8	8,530	1,451	11	10,080
Operating (loss) income	(6)	—	(38)	(8)	3,981	61	—	3,990
Other income (expense)								
Earnings from consolidated subsidiaries	2,025	3,251	163	759	1,986	1,755	(9,939)	—
Earnings from equity investments	—	—	—	—	323	4	—	327
Interest, net	(539)	41	(36)	(157)	(949)	(35)	—	(1,675)
Amortization of excess cost of equity investments and other, net	(1)	—	(1)	—	549	249	—	796
Income from continuing operations before income taxes	1,479	3,292	88	594	5,890	2,034	(9,939)	3,438
Income tax (expense) benefit	(41)	(11)	—	—	50	(740)	—	(742)
Income from continuing operations	1,438	3,281	88	594	5,940	1,294	(9,939)	2,696
Loss from discontinued operations	—	—	—	—	(4)	—	—	(4)
Net income	1,438	3,281	88	594	5,936	1,294	(9,939)	2,692
Net income attributable to noncontrolling interests	(245)	—	—	—	(236)	—	(1,018)	(1,499)
Net income attributable to controlling interests	$ 1,193	$ 3,281	$ 88	$ 594	$ 5,700	$ 1,294	$ (10,957)	$ 1,193

Net Income	$ 1,438	$ 3,281	$ 88	$ 594	$ 5,936	$ 1,294	$ (9,939)	$ 2,692
Total other comprehensive income (loss)	81	(135)	—	—	(145)	(172)	411	40
Comprehensive income	1,519	3,146	88	594	5,791	1,122	(9,528)	2,732
Comprehensive income attributable to noncontrolling interests	(232)	—	—	—	(237)	—	(976)	(1,445)
Comprehensive income attributable to controlling interests	$ 1,287	$ 3,146	$ 88	$ 594	$ 5,554	$ 1,122	$ (10,504)	$ 1,287

Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2012
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Issuer and Guarantor - EPB	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 35	$ —	$ —	$ —	$ 8,651	$ 1,265	$ 22	$ 9,973
Operating costs, expenses and other								
Costs of sales	—	—	—	—	2,761	271	25	3,057
Depreciation, depletion and amortization	19	—	—	—	1,091	309	—	1,419
Other operating expenses	295	—	—	2	2,172	438	(3)	2,904
Total operating costs, expenses and other	314	—	—	2	6,024	1,018	22	7,380
Operating (loss) income	(279)	—	—	(2)	2,627	247	—	2,593
Other income (expense)								
Earnings from consolidated subsidiaries	842	1,351	—	436	815	1,466	(4,910)	—
Earnings from equity investments	—	—	—	—	206	(53)	—	153
Interest, net	(630)	41	—	(69)	(757)	16	—	(1,399)
Amortization of excess cost of equity investments and other, net	(1)	—	—	—	(21)	18	—	(4)
(Loss) income from continuing operations before income taxes	(68)	1,392	—	365	2,870	1,694	(4,910)	1,343
Income tax benefit (expense)	392	(9)	—	—	98	(620)	—	(139)
Income from continuing operations	324	1,383	—	365	2,968	1,074	(4,910)	1,204
Loss from discontinued operations	(14)	—	—	—	(2)	(761)	—	(777)
Net income	310	1,383	—	365	2,966	313	(4,910)	427
Net loss (income) attributable to noncontrolling interests	5	—	—	—	(168)	—	51	(112)
	$ 315	$ 1,383	$ —	$ 365	$ 2,798	$ 313	$ (4,859)	$ 315

Net income attributable to controlling interests								
Net Income	$ 310	$ 1,383	$ —	$ 365	$ 2,966	$ 313	$ (4,910)	$ 427
Total other comprehensive income	12	165	—	10	200	96	(412)	71
Comprehensive income	322	1,548	—	375	3,166	409	(5,322)	498
Comprehensive income attributable to noncontrolling interests	(10)	—	—	—	(174)	—	(2)	(186)
Comprehensive income attributable to controlling interests	$ 312	$ 1,548	$ —	$ 375	$ 2,992	$ 409	$ (5,324)	$ 312

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Condensed Consolidating Balance Sheets as of December 31, 2014
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Issuer and Guarantor - EPB	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS								
Cash and cash equivalents	$4	$15	$—	$—	$17	$ 279	$ —	$ 315
Other current assets - affiliates	1,870	1,332	11	1	11,575	403	(15,192)	—
All other current assets	397	151	3	1	2,547	358	(20)	3,437
Property, plant and equipment, net	263	—	5	—	29,490	8,806	—	38,564
Investments	16	—	—	1	5,910	109	—	6,036
Investments in subsidiaries	31,364	27,264	1,911	6,150	16,387	3,337	(86,413)	—
Goodwill	15,087	—	920	22	5,419	3,206	—	24,654
Notes receivable from affiliates	4,459	19,824	—	8	3,621	496	(28,408)	—
Deferred tax assets	—	—	—	—	9,251	—	(3,600)	5,651
Other non-current assets	287	341	—	19	3,782	112	—	4,541
Total assets	$53,747	$48,927	$2,850	$6,202	$87,999	$ 17,106	$ (133,633)	$ 83,198
LIABILITIES AND STOCKHOLDERS' EQUITY								
Liabilities								
Current portion of debt	$1,486	$324	$—	$375	$381	$ 151	$ —	$ 2,717
Other current liabilities - affiliates	709	11,926	115	23	1,553	866	(15,192)	—
All other current liabilities	318	463	12	34	1,814	1,024	(20)	3,645
Long-term debt	11,862	18,197	386	2,478	6,609	714	—	40,246
Notes payable to affiliates	2,619	153	753	1,206	22,437	1,240	(28,408)	—
Deferred income taxes	2,094	—	2	—	—	1,504	(3,600)	—
All other long-term liabilities and deferred credits	583	78	2	—	987	514	—	2,164
Total liabilities	19,671	31,141	1,270	4,116	33,781	6,013	(47,220)	48,772
Stockholders' equity								
Total KMI equity	34,076	17,786	1,580	2,086	54,218	11,093	(86,763)	34,076

Noncontrolling interests	—	—	—	—	—	—	350	350
Total stockholders' equity	34,076	17,786	1,580	2,086	54,218	11,093	(86,413)	34,426
Total liabilities and stockholders' equity	$ 53,747	$ 48,927	$ 2,850	$ 6,202	$ 87,999	$ 17,106	$ (133,633)	$ 83,198

Condensed Consolidating Balance Sheets as of December 31, 2013
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Issuer and Guarantor - EPB	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS								
Cash and cash equivalents	$ 83	$ 10	$ 1	$ 78	$ 17	$ 409	$ —	$ 598
Other current assets - affiliates	287	751	—	18	10,992	220	(12,268)	—
All other current assets	657	136	2	—	2,184	302	(11)	3,270
Property, plant and equipment, net	284	—	170	—	26,698	8,695	—	35,847
Investments	17	—	—	—	5,822	112	—	5,951
Investments in subsidiaries	13,618	26,555	4,430	4,445	3,584	3,839	(56,471)	—
Goodwill	15,099	—	813	22	5,317	3,253	—	24,504
Notes receivable from affiliates	—	17,284	—	—	3,087	511	(20,882)	—
Other non-current assets	455	233	—	20	3,866	441	—	5,015
Total assets	$ 30,500	$ 44,969	$ 5,416	$ 4,583	$ 61,567	$ 17,782	$ (89,632)	$ 75,185
LIABILITIES AND STOCKHOLDERS' EQUITY								
Liabilities								
Current portion of debt	$ 575	$ 1,504	$—	$—	$ 77	$ 150	$ —	$ 2,306
Other current liabilities - affiliates	379	10,453	55	19	823	539	(12,268)	—
All other current liabilities	72	394	41	30	1,728	1,515	(11)	3,769
Long-term debt	7,775	15,644	393	2,253	7,101	721	—	33,887
Notes payable to affiliates	1,993	—	907	1,143	15,599	1,240	(20,882)	—
Deferred income taxes	2,022	—	2	—	1,142	1,485	—	4,651
Other long-term liabilities and deferred credits	384	173	—	—	1,023	707	—	2,287
Total liabilities	13,200	28,168	1,398	3,445	27,493	6,357	(33,161)	46,900
Stockholders' equity								
Total KMI equity	13,093	16,801	4,018	1,138	31,025	11,478	(64,460)	13,093
	4,207	—	—	—	3,049	(53)	7,989	15,192

Noncontrolling interests								
Total stockholders' equity	17,300	16,801	4,018	1,138	34,074	11,425	(56,471)	28,285
Total liabilities and stockholders' equity	$30,500	$44,969	$5,416	$4,583	$61,567	$ 17,782	$ (89,632)	$ 75,185

Condensed Consolidating Statements of Cash Flows for the Year Ended December 31, 2014
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Issuer and Guarantor - EPB	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash provided by (used in) operating activities	$ 1,426	$ 3,998	$ (77)	$ 885	$ 6,345	$ 1,174	$ (9,284)	$ 4,467
Cash flows from investing activities								
Funding to affiliates	(1,756)	(6,559)	—	(1,252)	(4,706)	(1,088)	15,361	—
Capital expenditures	(1)	—	(63)	—	(3,050)	(705)	202	(3,617)
Sale, casualty and transfer of property, plant and equipment, investments and other net assets, net of removal costs	—	—	202	—	(9)	14	(202)	5
Contributions to investments	—	—	—	(189)	(594)	—	394	(389)
Investments in KMP and EPB	(550)	—	—	—	—	—	550	—
Acquisitions of assets and investments	—	—	—	—	(1,370)	(18)	—	(1,388)
Drop down assets to EPB	875	—	—	—	(875)	—	—	—
Distributions from equity investments in excess of cumulative earnings	93	—	—	440	183	—	(534)	182
Other, net	—	29	—	—	27	(60)	1	(3)
Net cash (used in) provided by investing activities	(1,339)	(6,530)	139	(1,001)	(10,394)	(1,857)	15,772	(5,210)
Cash flows from financing activities								
Issuance of debt	10,594	13,057	—	922	—	—	—	24,573
Payment of debt	(5,479)	(11,849)	—	(322)	(142)	(9)	—	(17,801)
Funding from (to) affiliates	756	3,823	(63)	786	9,138	921	(15,361)	—
Debt issuance costs	(74)	(11)	—	(4)	—	—	—	(89)
Cash dividends	(1,760)	—	—	—	—	—	—	(1,760)
Repurchases of shares and warrants	(192)	—	—	—	—	—	—	(192)
Cash consideration of Merger Transactions	(3,937)	—	—	—	—	—	—	(3,937)
	(74)	—	—	—	—	—	—	(74)

Merger Transactions costs								
Contributions from parents	—	1,178	—	205	1,267	64	(2,714)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	1,767	1,767
Distributions to parents	—	(3,660)	—	(1,549)	(6,213)	(411)	11,833	—
Distributions to noncontrolling interests	—	—	—	—	—	—	(2,013)	(2,013)
Other, net	—	(1)	—	—	(2)	—	—	(3)
Net cash (used in) provided by financing activities	(166)	2,537	(63)	38	4,048	565	(6,488)	471
Effect of exchange rate changes on cash and cash equivalents	—	—	—	—	1	(12)	—	(11)
Net (decrease) increase in cash and cash equivalents	(79)	5	(1)	(78)	—	(130)	—	(283)
Cash and cash equivalents, beginning of period	83	10	1	78	17	409	—	598
Cash and cash equivalents, end of period	$ 4	$ 15	$ —	$ —	$ 17	$ 279	$ —	$ 315

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Condensed Consolidating Statements of Cash Flows for the Year Ended December 31, 2013
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Issuer and Guarantor - EPB	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash provided by (used in) operating activities	$ 1,775	$ 4,173	$ (408)	$ 64	$ 5,491	$ 769	$ (7,742)	$ 4,122
Cash flows from investing activities								
Funding to affiliates	(402)	(7,145)	(1)	(661)	(4,270)	(1,332)	13,811	—
Capital expenditures	(6)	—	(141)	—	(2,418)	(804)	—	(3,369)
Sale or casualty of property, plant and equipment, investments and other net assets, net of removal costs	—	—	—	—	87	—	—	87
Proceeds from sale of assets and investments	—	—	—	—	118	372	—	490
Contributions to investments	(6)	—	—	(52)	(218)	—	59	(217)
Investments in KMP and EPB	(68)	—	—	—	—	—	68	—
Acquisitions of assets and investments	—	—	5	—	(297)	—	—	(292)
Drop down assets to KMP	994	—	—	—	(994)	—	—	—
Distributions from equity investments in excess of cumulative earnings	41	—	—	296	183	—	(335)	185
Other, net	—	(12)	—	—	18	(12)	—	(6)
Net cash provided by (used in) investing activities	553	(7,157)	(137)	(417)	(7,791)	(1,776)	13,603	(3,122)
Cash flows from financing activities								
Issuance of debt	3,028	10,213	—	87	14	239	—	13,581
Payment of debt	(3,624)	(7,627)	(854)	(175)	(106)	(7)	—	(12,393)
Funding from affiliates	576	1,971	1,400	1,332	7,740	792	(13,811)	—
Debt issuance costs	(15)	(22)	—	—	—	(1)	—	(38)
Cash dividends	(1,622)	—	—	—	—	—	—	(1,622)
Repurchases of shares and warrants	(637)	—	—	—	—	—	—	(637)
Contributions from parents	—	1,533	—	1	162	132	(1,828)	—

Contributions from noncontrolling interests	—	—	—	—	—	—	1,706	1,706
Distributions to parents	—	(3,168)	—	(924)	(5,522)	(150)	9,764	—
Distributions to noncontrolling interests	—	—	—	—	—	—	(1,692)	(1,692)
Other, net	1	(1)	—	—	—	—	—	—
Net cash (used in) provided by financing activities	(2,293)	2,899	546	321	2,288	1,005	(5,861)	(1,095)
Effect of exchange rate changes on cash and cash equivalents	—	—	—	—	1	(22)	—	(21)
Net increase (decrease) in cash and cash equivalents	35	(85)	1	(32)	(11)	(24)	—	(116)
Cash and cash equivalents, beginning of period	48	95	—	110	28	433	—	714
Cash and cash equivalents, end of period	$ 83	$ 10	$ 1	$ 78	$ 17	$ 409	$ —	$ 598

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Condensed Consolidating Statements of Cash Flows for the Year Ended December 31, 2012
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Issuer and Guarantor - EPB	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash provided by (used in) operating activities	$ 657	$ 3,867	$ —	$ (151)	$ 3,095	$ 941	$ (5,601)	$ 2,808
Cash flows from investing activities								
Funding (to) from affiliates	(857)	(5,521)	—	42	(3,515)	(1,448)	11,299	—
Capital expenditures	(5)	—	—	—	(1,423)	(594)	—	(2,022)
Sale or casualty of property, plant and equipment, investments and other net assets, net of removal costs	—	—	—	—	64	90	—	154
Acquisition of EP	(5,212)			81	70	91	—	(4,970)
Contributions to investments	(15)	—	—	(454)	(206)	—	483	(192)
Investments in KMP and EPB	(94)	—	—	—	—	—	94	—
Acquisitions of assets and investments	—	—	—	—	(83)	—	—	(83)
Drop down assets to KMP	3,485	—	—	—	(3,485)	—	—	—
Distributions from equity investments in excess of cumulative earnings	16	—	—	106	184	—	(106)	200
Proceeds from disposal of discontinued operations	—	—	—	—	1,791	—	—	1,791
Other, net	—	(15)	—	—	121	(81)	—	25
Net cash used in investing activities	(2,682)	(5,536)	—	(225)	(6,482)	(1,942)	11,770	(5,097)
Cash flows from financing activities								
Issuance of debt	8,001	9,270	—	658	—	219	—	18,148
Payment of debt	(5,692)	(8,003)	—	(855)	(205)	—	—	(14,755)
Funding from affiliates	1,268	1,360	—	1,049	6,612	1,010	(11,299)	—
Debt issuance costs	(91)	(16)	—	(4)	—	—	—	(111)
Cash dividends	(1,184)	—	—	—	—	—	—	(1,184)
Repurchases of shares and warrants	(157)	—	—	—	—	—	—	(157)
Contributions from parents	—	1,681	—	29	763	30	(2,503)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	1,939	1,939
Distributions to parents	—	(2,528)	—	(391)	(3,763)	(231)	6,913	—

Distributions to noncontrolling interests	—	—	—	—	—	—	(1,219)	(1,219)
Other, net	(74)	(1)	—	—	(2)	—	—	(77)
Net cash provided by financing activities	2,071	1,763	—	486	3,405	1,028	(6,169)	2,584
Effect of exchange rate changes on cash and cash equivalents	—	—	—	—	—	8	—	8
Net increase in cash and cash equivalents	46	94	—	110	18	35	—	303
Cash and cash equivalents, beginning of period	2	1	—	—	10	398	—	411
Cash and cash equivalents, end of period	$ 48	$ 95	$ —	$ 110	$ 28	$ 433	$ —	$ 714

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Supplemental Selected Quarterly Financial Data (Unaudited)

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
2014				
Revenues	$4,047	$3,937	$4,291	$3,951
Operating Income	1,147	1,013	1,332	956
Net Income	601	497	779	566
Net Income Attributable to Kinder Morgan, Inc.	287	284	329	126
Basic and Diluted Earnings Per Common Share	0.28	0.27	0.32	0.08
2013				
Revenues	$3,060	$3,382	$3,756	$3,872
Operating Income	1,017	772	1,041	1,160
Net Income	656	781	551	704
Net Income Attributable to Kinder Morgan, Inc.	292	277	286	338
Basic and Diluted Earnings Per Common Share	0.28	0.27	0.27	0.33

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Supplemental Information on Oil and Gas Producing Activities (Unaudited)

Operating statistics from our oil and gas producing activities for each of the years ended December 31, 2014, 2013 and 2012 are shown in the following table:

Results of Operations for Oil and Gas Producing Activities – Unit Prices and Costs

	Year Ended December 31,		
	2014	2013	2012
Consolidated Companies(a)			
Production costs per barrel of oil equivalent(b)(c)(d)	$20.55	$18.81	$16.44
Crude oil production (MBbl/d)	40.8	37.6	35.0
SACROC crude oil production (MBbl/d)	27.6	25.5	24.1
Yates crude oil production (MBbl/d)	8.8	9.0	9.3
NGL production (MBbl/d)(d)	4.2	4.1	3.9
NGL production from gas plants(MBbl/d)(e)	5.9	5.8	5.6
Total NGL production(MBbl/d)	10.1	9.9	9.5
SACROC NGL production (MBbl/d)(d)	3.9	3.8	3.7
Yates NGL production (MBbl/d)(d)	0.2	0.2	0.2
Natural gas production (MMcf/d)(d)(f)	1.0	1.1	1.2
Natural gas production from gas plants(MMcf/d)(e)(f)	1.2	1.7	0.7
Total natural gas production(MMcf/d)(f)	2.2	2.8	1.9
Yates natural gas production (MMcf/d)(d)(f)	1.0	1.1	1.1
Average sales prices including hedge gains/losses:			
Crude oil price per Bbl(g)	$88.41	$92.70	$87.72
NGL price per Bbl(d)(g)	$42.61	$46.11	$51.79
Natural gas price per Mcf(d)(h)	$4.04	$3.23	$2.58
Total NGL price per Bbl(e)	$41.87	$46.43	$50.95
Total natural gas price per Mcf(e)	$3.91	$3.21	$2.72
Average sales prices excluding hedge gains/losses:			
Crude oil price per Bbl(g)	$86.48	$94.94	$89.91
NGL price per Bbl(g)	$42.61	$46.11	$51.79
Natural gas price per Mcf(h)	$4.04	$3.23	$2.58

(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.
(b) Computed using production costs, excluding transportation costs, as defined by the SEC. Natural gas volumes were converted to barrels of oil equivalent using a conversion factor of six Mcf of natural gas to one barrel of oil.
(c) Production costs include labor, repairs and maintenance, materials, supplies, fuel and power, and general and administrative expenses directly related to oil and gas producing activities.
(d) Includes only production attributable to leasehold ownership.
(e) Includes production attributable to our ownership in processing plants and third party processing agreements.
(f) Excludes natural gas production used as fuel.
(g) Hedge gains/losses for crude oil and NGL are included with crude oil.
(h) Natural gas sales were not hedged.

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The following three tables provide supplemental information on oil and gas producing activities, including (i) capitalized costs related to oil and gas producing activities; (ii) costs incurred for the acquisition of oil and gas producing properties and for exploration and development activities; and (iii) the results of operations from oil and gas producing activities.

Our capitalized costs consisted of the following (in millions):

Capitalized Costs Related to Oil and Gas Producing Activities

	As of December 31,		
	2014	2013	2012
Consolidated Companies(a)			
Wells and equipment, facilities and other	$4,937	$4,432	$3,927
Leasehold	658	660	428
Total proved oil and gas properties	5,595	5,092	4,355
Unproved property(b)	103	38	8
Accumulated depreciation and depletion(c)	(4,226)	(3,520)	(3,072)
Net capitalized costs	$1,472	$1,610	$1,291

(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries. Includes capitalized asset retirement costs and associated accumulated depreciation.

(b) As of December 31, 2014, capitalized costs related to the unproved property for the Residual Oil Zone (ROZ) unproved exploration property was $100 million and other miscellaneous unproved property was $3 million.

(c) 2014 amount includes an impairment charge of $234 million on the Katz Strawn unit and $1 million on other miscellaneous property.

For each of the years ended December 31, 2014 , 2013 and 2012, our costs incurred for property acquisition, development and exploration were as follows (in millions):

Costs Incurred in Exploration, Property Acquisitions and Development

	Year Ended December 31,		
	2014	2013	2012
Consolidated Companies			
Acquisitions(a)	$—	$285	$—
Development(b)	481	471	310
Exploration(c)	95	11	—

(a) Acquisition of Goldsmith Landreth San Andres Unit effective June 1, 2013.

(b) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.

(c) Amounts relate to exploration wells drilled in the Residual Oil Zone (ROZ) for $87 million and the Yates Wolfcamp for $8 million.

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Our results of operations from oil and gas producing activities for each of the years ended December 31, 2014, 2013 and 2012 are shown in the following table (in millions):

Results of Operations for Oil and Gas Producing Activities

	Year Ended December 31,		
	2014	2013	2012
Consolidated Companies(a)			
Revenues(b)	$1,412	$1,376	$1,235
Expenses:			
Production costs	403	344	288
Other operating expenses(c)	99	95	77
Exploration expense(d)	8	—	—
Impairment(e)	235	—	—
DD&A expenses	430	415	387
Total expenses	1,175	854	752
Results of operations for oil and gas producing activities	$237	$522	$483

(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.
(b) Revenues include a gain attributable to our hedging contracts of $28 million, for the year ended December 31, 2014 and losses of $31 million and $28 million for each of the years, 2013 and 2012, respectively.
(c) Consists primarily of CO_2 expense.
(d) Exploration charge for Yates Wolfcamp.
(e) Impairment charge of $234 million on the Katz Strawn unit and $1 million on other miscellaneous property.

Supplemental information is also provided for the following three items (i) estimated quantities of proved oil and gas reserves; (ii) the standardized measure of discounted future net cash flows associated with proved oil and gas reserves; and (iii) a summary of the changes in the standardized measure of discounted future net cash flows associated with proved oil and gas reserves.

The technical persons responsible for preparing the reserves estimates presented in this Supplemental Information meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the standards pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. They are independent petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our oil and gas properties; and we do not employ them on a contingent basis.

The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Derek Newton and Mr. Mike Norton. Mr. Newton, a Licensed Professional
Engineer in the State of Texas (No. 97689), has been practicing consulting petroleum engineering at NSAI since 1997 and has over 14 years of prior industry experience. He graduated from University College, Cardiff, Wales, in 1983 with a Bachelor of Science Degree in Mechanical Engineering and from Strathclyde University, Scotland, in 1986 with a Master of Science Degree in Petroleum Engineering. Mr. Norton, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1989 and has over 10 years of prior industry experience. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the

Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Our employee who is primarily responsible for overseeing NSAI's preparation of the reserves estimates is a registered Professional Engineer in the states of Texas and Kansas with a Doctorate of Engineering from the University of Kansas. He is a member of the Society of Petroleum Engineers and has over 30 years of professional engineering experience. We believe the geologic and engineering data examined provides reasonable assurance that the proved reserves are recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are subject to change, either positively or negatively, as additional information become available and contractual and economic conditions change.

Furthermore, our management is responsible for establishing and maintaining adequate internal control over financial reporting, which includes the estimation of our oil and gas reserves. We maintain internal controls and guidance to ensure the reliability of our crude oil, NGL and natural gas reserves estimations, as follows:

- no employee's compensation is tied to the amount of recorded reserves;
- we follow comprehensive SEC compliant internal policies to determine and report proved reserves, and our reserve estimates are made by experienced oil and gas reservoir engineers or under their direct supervision;
- we review our reported proved reserves at each year-end, and at each year-end, the CO_2 business segment managers and the Vice President (President, CO_2) review all significant reserves changes and all new proved developed and undeveloped reserves additions; and
- the CO_2 business segment reports independently of our five remaining reportable business segments.

For more information on our controls and procedures, see Item 9A "Controls and Procedures-Management's Report on Internal Control Over Financial Reporting" included in our Annual Report on Form 10-K for the year ended December 31, 2014.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and NGL which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, current prices and costs calculated as of the date the estimate is made. Pricing is applied based upon the twelve month unweighted arithmetic average of the first day of the month price for the year. Future development and production costs are determined based upon actual cost at year-end. Proved developed reserves are the quantities of crude oil, NGL and natural gas expected to be recovered through existing investments in wells and field infrastructure under current operating conditions. Proved undeveloped reserves require additional investments in wells and related infrastructure in order to recover the production.

As of December 31, 2012, we had 53.0 MMBbl of crude oil and 2.4 MMBbl of NGL classified as proved developed reserves. Also, as of year end 2012, we had 28.9 MMBbl of crude oil and 3.5 MMBbl of NGL classified as proved undeveloped reserves. Total proved reserves as of December 31, 2012, were 82.0 MMBbl of crude oil and 6.0 MMBbl of NGL.

During 2013, production from the fields totaled 13.7 MMBbl of crude oil and 1.5 MMBbl of NGL. For 2013, we incurred $452 million in capital costs, and this capital investment resulted in the development of 11.0 MMBbl of crude oil and 1.3 MMBbl of NGL and their transfer from the proved undeveloped category to the proved developed category. During 2013, we acquired the Goldsmith Landreth San Andres Field Unit which increased proved developed reserves by 15.5 MMBbl of crude oil and 3.9 MMBbl of NGL. The reclassifications from proved undeveloped to proved developed reserves reflect the transfer of 38.1% of crude oil and 37.5% of NGL from the proved undeveloped reserves reported as of December 31, 2012 to the proved developed classification of reserves reported as of December 31, 2013. The developed reserves for the Goldsmith Landreth San Andres Field Unit represent 25.9% of proved developed reserves.

Also during 2013, previous estimates of proved developed reserves were revised upward by 1.7 MMBbl of crude oil and 0.6 MMBbl of NGL, and proved undeveloped reserves were revised downward by 4.3 MMBbl of crude oil and 0.65 MMBbl of NGL. These revisions are mainly attributed to the elimination of uneconomic proved developed nonproducing reserves and proved undeveloped reserves in Katz due to higher operating costs. The proved developed reserves for Katz represent 6.3% of proved developed reserves.

These revisions to our previous estimates, as well as the transfer of proved undeveloped reserves to the proved developed category as discussed above, resulted in the percentage of proved undeveloped reserves increasing from 36.4% at year end 2012 to 39.0% at year end 2013. After giving effect to production and revisions to previous estimates during 2013, total proved reserves of crude oil increased by 25.1 MMBbl and total proved reserves of NGL increased by 8.8 MMBbl.

As of December 31, 2013, we had 67.4 MMBbl of crude oil and 6.7 MMBbl of NGL classified as proved developed reserves. Also, as of year end 2013, we had 39.6 MMBbl of crude oil and 8.0 MMBbl of NGL classified as proved undeveloped reserves. Total proved reserves as of December 31, 2013, were 107.0 MMBbl of crude oil and 14.8 MMBbl of NGL.

During 2014, production from the fields totaled 14.8 MMBbl of crude oil and 1.5 MMBbl of NGL. For 2014, we incurred $502 million in capital costs, and this capital investment resulted in the development of 5.7 MMBbl of crude oil and their

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transfer from the proved undeveloped category to the proved developed category. The reclassifications from proved undeveloped to proved developed reserves reflect the transfer of 14.5% of crude oil from the proved undeveloped reserves reported as of December 31, 2013 to the proved developed classification of reserves reported as of December 31, 2014. Revisions to previous transfers of NGL’s resulted a downward revision of 0.1 MMBbl for NGL‘s in the proved developed category that have been reclassified to the proved undeveloped category as of December 31, 2014. This reclassification reflects the transfer of 1.8% of proved developed NGL’s reported as of December 31, 2013 to the proved undeveloped classification of reserves reported as of December 31, 2014.

Also during 2014, previous estimates of proved developed reserves were revised upward by 2.0 MMBbl of crude oil and downward 0.5 MMBbl of NGL, and proved undeveloped reserves were revised upward by 3.4 MMBbl of crude oil and downward 1.9 MMBbl of NGL. These revisions are mainly attributed to the addition of projects and the use of higher projected oil recoveries resulting from updated performance at SACROC used to calculate reserves. The proved developed reserves for SACROC represent 32.5% of proved developed reserves. The Katz Strawn Unit also received an addition of proved developed nonproducing reserves volumes. The proved developed reserves for Katz Strawn Unit represent 12.3% of proved developed reserves. Contrarily, there was also a decrease of proved developed producing reserves and proved undeveloped reserves in Goldsmith due to higher operating costs and lower well performance. The proved developed reserves for Goldsmith represent 13.4% of proved developed reserves.

These revisions to our previous estimates, as well as the transfer of proved undeveloped reserves to the proved developed category as discussed above, resulted in the percentage of proved undeveloped reserves increasing from 39.0% at year end 2013 to 40.0% at year end 2014. After giving effect to production and revisions to previous estimates during 2014, total proved reserves of crude oil decreased by 9.5 MMBbl and total proved reserves of NGL decreased by 4.0 MMBbl.

As of December 31, 2014, we had 60.3 MMBbl of crude oil and 4.6 MMBbl of NGL classified as proved developed reserves. Also, as of year end 2014, we had 37.3 MMBbl of crude oil and 6.2 MMBbl of NGL classified as proved undeveloped reserves. Total proved reserves as of December 31, 2014, were 97.6 MMBbl of crude oil and 10.8 MMBbl of NGL. We currently expect that the proved undeveloped reserves we report as of December 31, 2014 will be developed within the next five years.

During 2014, we filed estimates of our oil and gas reserves for the year 2013 with the Energy Information Administration of the U. S. Department of Energy on Form EIA-23. The data on Form EIA-23 was presented on a different basis, and included 100% of the oil and gas volumes from our operated properties only, regardless of our net interest. The difference between the oil and gas reserves reported on Form EIA-23 and those reported in this Supplemental Information exceeds 5%.

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The following Reserve Quantity Information table discloses estimates, as of December 31, 2014, of proved crude oil, NGL and natural gas reserves, prepared by Netherland, Sewell & Associates, Inc. (independent oil and gas consultants), of $KMCO_2$ and its consolidated subsidiaries' interests in oil and gas properties, all of which are located in the state of Texas. This data has been prepared using current prices and costs, as discussed above, and the estimates of reserves and future revenues in this Supplemental Information conform to the guidelines of the SEC.

Reserve Quantity Information

	Consolidated Companies(a)		
	Crude Oil (MBbl)	NGL (MBbl)	Natural Gas (MMcf)(b)
Proved developed and undeveloped reserves:			
As of December 31, 2011	79,447	4,145	3,241
Revisions of previous estimates(c)	15,540	3,285	4,881
Extensions and discoveries	26	—	—
Sales of reserves in place	(239)	(38)	(143)
Production	(12,824)	(1,416)	(440)
As of December 31, 2012	81,950	5,976	7,539
Revisions of previous estimates(d)	(2,573)	(43)	(5,063)
Purchases of reserves in place(e)	41,389	10,347	—
Production	(13,735)	(1,499)	(406)
As of December 31, 2013	107,031	14,781	2,070
Revisions of previous estimates(f)	5,378	(2,419)	372
Production	(14,852)	(1,542)	(373)
As of December 31, 2014	97,557	10,820	2,069
Proved developed reserves:			
As of December 31, 2012	53,006	2,433	7,539
As of December 31, 2013	67,436	6,733	2,070
As of December 31, 2014	60,252	4,584	2,069
Proved undeveloped reserves:			
As of December 31, 2012	28,944	3,543	—
As of December 31, 2013	39,595	8,048	—
As of December 31, 2014	37,305	6,236	—

(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.
(b) Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.
(c) Predominantly due to higher CO_2 flood recoveries based on updated performance at the SACROC Unit.
(d) Predominantly due to higher operating costs at the Katz Strawn Unit.
(e) Represents volumes added with acquisition of the Goldsmith Landreth San Andres Unit in June 2013.
(f) Predominately due to the addition of projects and redefined original oil in place values at SACROC, the addition of proved developed nonproducing reserves volumes in the Katz Strawn Unit offset by decreased expected oil recoveries in the Goldsmith Landreth San Andres Unit based on higher operating costs and lower well performance.

The standardized measure of discounted cash flows and summary of the changes in the standardized measure computation from year-to-year are prepared in accordance with the "Extractive Activities—Oil and Gas" Topic of the Codification. The assumptions that underly the computation of the standardized measure of discounted cash flows, presented in the table below, may be summarized as follows:

- the standardized measure includes our estimate of proved crude oil, NGL and natural gas reserves and projected future production volumes based upon year-end economic conditions;

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- pricing is applied based upon the 12 month unweighted arithmetic average of the first day of the month price for the year;
- future development and production costs are determined based upon actual cost at year-end;
- the standardized measure includes projections of future abandonment costs based upon actual costs at year-end; and
- a discount factor of 10% per year is applied annually to the future net cash flows.

The standardized measure of discounted future net cash flows from proved reserves were as follows (in millions):

Standardized Measure of Discounted Future Net Cash Flows From
Proved Oil and Gas Reserves

	As of December 31,		
	2014	2013	2012
Consolidated Companies(a)			
Future cash inflows from production	$9,406	$10,945	$7,807
Future production costs	(4,294)	(4,214)	(2,923)
Future development costs(b)	(2,113)	(1,948)	(1,011)
Undiscounted future net cash flows	2,999	4,783	3,873
10% annual discount	(1,089)	(2,096)	(1,168)
Standardized measure of discounted future net cash flows(c)	$1,910	$2,687	$2,705

(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.
(b) Includes abandonment costs.
(c) Standardized Measure of discounted future net cash flows as of December 31, 2013 includes $843 million attributable to the Goldsmith Landreth San Andres Unit acquired in June 2013.

The following table represents our estimate of changes in the standardized measure of discounted future net cash flows from proved reserves (in millions):

Changes in the Standardized Measure of Discounted Future Net Cash Flows From
Proved Oil and Gas Reserves

	As of December 31,		
	2014	2013	2012
Consolidated Companies(a)			
Present value as of January 1	$2,687	$2,705	$2,194
Changes during the year:			
Revenues less production and other costs(b)	(880)	(965)	(895)
Net changes in prices, production and other costs	(504)	258	(88)
Development costs incurred	502	452	353
Net changes in future development costs	(479)	(629)	64
Improved recovery	—	—	—
Extensions and discoveries(c)	—	—	5
Sales of reserves in place(d)	—	—	(5)
Revisions of previous quantity estimates(e)	329	(114)	871
Purchase of reserves in place(f)	—	683	—
Accretion of discount	255	297	206
Net change for the year	(777)	(18)	511
Present value as of December 31	$1,910	$2,687	$2,705

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(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.

(b) Excludes a gain attributable to our hedging contracts of $28 million for the year ended December 31, 2014 and losses of $31 million and $28 million for the years 2013 and 2012, respectively.

(c) Primarily due to the extension of the SACROC unit.

(d) Sale of the Claytonville field unit.

(e) 2014 revisions were primarily due to, increases due to the addition of projects and redefined original oil in place values at SACROC, additional proved developed nonproducing reserves volumes in the Katz Strawn Unit offset by decreased oil recoveries and higher operating costs for the Goldsmith Landreth San Andres Unit. 2013 revisions were primarily due to increased operating costs at the Katz Strawn Unit. 2012 revisions were primarily due to higher projected CO_2 flood recoveries resulting from updated performance at SACROC and the addition of proved undeveloped reserve volumes at the Katz Strawn Unit CO_2 flood.

(f) Acquisition of the Goldsmith Landreth San Andres Unit in June 2013.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

KINDER MORGAN, INC.
Registrant

By: /s/ KIMBERLY A. DANG
Kimberly A. Dang
Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: February 23, 2015

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Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ KIMBERLY A. DANG Kimberly A. Dang	Vice President and Chief Financial Officer (principal financial officer and principal accounting officer)	February 23, 2015
/s/ RICHARD D. KINDER Richard D. Kinder	Director, Chairman and Chief Executive Officer (principal executive officer)	February 23, 2015
/s/ TED A. GARDNER Ted A. Gardner	Director	February 23, 2015
/s/ ANTHONY W. HALL, JR. Anthony W. Hall, Jr.	Director	February 23, 2015
/s/ GARY L. HULTQUIST Gary L. Hultquist	Director	February 23, 2015
/s/ STEVEN J. KEAN Steven J. Kean	Director	February 23, 2015
/s/ RONALD L. KUEHN, JR. Ronald L. Kuehn, Jr.	Director	February 23, 2015
/s/ DEBORAH A. MACDONALD Deborah A. Macdonald	Director	February 23, 2015
/s/ MICHAEL J. MILLER Michael J. Miller	Director	February 23, 2015
/s/ MICHAEL C. MORGAN Michael C. Morgan	Director	February 23, 2015
/s/ ARTHUR C. REICHSTETTER Arthur C. Reichstetter	Director	February 23, 2015
/s/ FAYEZ SAROFIM Fayez Sarofim	Director	February 23, 2015
/s/ C. PARK SHAPER C. Park Shaper	Director	February 23, 2015
/s/ WILLIAM A. SMITH William A. Smith	Director	February 23, 2015
/s/ JOEL V. STAFF	Director	February 23, 2015

Joel V. Staff

/s/ ROBERT F. VAGT Robert F. Vagt	Director	February 23, 2015
/s/ PERRY M. WAUGHTAL Perry M. Waughtal	Director	February 23, 2015