UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2014

OR

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

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**76-0568219**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1100 Louisiana Street, 10th Floor
Houston, Texas 77002
(Address of Principal Executive Offices, including Zip Code)

(713) 381-6500
(Registrant's Telephone Number, including Area Code)

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 ☑ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No ☑

There were 938,965,811 common units of Enterprise Products Partners L.P. outstanding at the close of business on July 31, 2014. Our common units trade on the New York Stock Exchange under the ticker symbol "EPD."

ENTERPRISE PRODUCTS PARTNERS L.P.
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PART I. FINANCIAL INFORMATION.

Item 1. *Financial Statements*.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

ASSETS	June 30, 2014	December 31, 2013
Current assets:		
Cash and cash equivalents	$ 242.0	$ 56.9
Restricted cash	56.7	65.6
Accounts receivable – trade, net of allowance for doubtful accounts of $14.8 at June 30, 2014 and $7.5 at December 31, 2013	5,393.5	5,475.5
Accounts receivable – related parties	56.3	6.8
Inventories	1,318.3	1,093.1
Prepaid and other current assets	405.1	325.5
Total current assets	7,471.9	7,023.4
Property, plant and equipment, net	27,554.7	26,946.6
Investments in unconsolidated affiliates	2,879.3	2,437.1
Intangible assets, net of accumulated amortization of $1,194.3 at June 30, 2014 and $1,150.0 at December 31, 2013	1,414.9	1,462.2
Goodwill (see Note 8)	2,079.9	2,080.0
Other assets	170.6	189.4
Total assets	$ 41,571.3	$ 40,138.7
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 9)	$ 1,300.0	$ 1,125.0
Accounts payable – trade	705.9	723.7
Accounts payable – related parties	114.0	150.5
Accrued product payables	5,606.6	5,608.7
Accrued interest	319.6	304.3
Other current liabilities	423.8	326.5
Total current liabilities	8,469.9	8,238.7
Long-term debt (see Note 9)	17,062.9	16,226.5
Deferred tax liabilities	61.2	60.8
Other long-term liabilities	174.9	172.3
Commitments and contingencies (see Note 14)		
Equity: (see Note 10)		
Partners' equity:		
Limited partners:		
Common units (938,975,136 units outstanding at June 30, 2014 and 935,685,008 units outstanding at December 31, 2013)	15,930.8	15,573.8
Accumulated other comprehensive loss	(354.2)	(359.0)
Total partners' equity	15,576.6	15,214.8
Noncontrolling interests	225.8	225.6
Total equity	15,802.4	15,440.4
Total liabilities and equity	$ 41,571.3	$ 40,138.7

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in millions, except per unit amounts)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
Revenues:				
Third parties	$ 12,503.5	$ 11,142.6	$ 25,377.9	$ 22,519.8
Related parties	17.3	6.7	52.8	12.6
Total revenues (see Note 11)	12,520.8	11,149.3	25,430.7	22,532.4
Costs and expenses:				
Operating costs and expenses:				
Third parties	11,382.4	10,143.0	23,000.8	20,349.2
Related parties	256.7	224.2	518.8	438.4
Total operating costs and expenses	11,639.1	10,367.2	23,519.6	20,787.6
General and administrative costs:				
Third parties	18.9	17.5	41.9	37.2
Related parties	28.8	28.0	59.0	57.8
Total general and administrative costs	47.7	45.5	100.9	95.0
Total costs and expenses (see Note 11)	11,686.8	10,412.7	23,620.5	20,882.6
Equity in income of unconsolidated affiliates	50.3	37.6	106.8	82.1
Operating income	884.3	774.2	1,917.0	1,731.9
Other income (expense):				
Interest expense	(228.9)	(200.2)	(449.8)	(396.1)
Interest income	0.5	0.3	0.8	0.5
Other, net	0.6	(0.6)	--	(0.9)
Total other expense, net	(227.8)	(200.5)	(449.0)	(396.5)
Income before income taxes	656.5	573.7	1,468.0	1,335.4
Provision for income taxes	(10.0)	(20.4)	(14.8)	(26.8)
Net income	646.5	553.3	1,453.2	1,308.6
Net income attributable to noncontrolling interests (see Note 10)	(8.8)	(0.8)	(16.7)	(2.6)
Net income attributable to limited partners	$ 637.7	$ 552.5	$ 1,436.5	$ 1,306.0
Earnings per unit: (see Note 13)				
Basic earnings per unit	$ 0.70	$ 0.62	$ 1.57	$ 1.48
Diluted earnings per unit	$ 0.68	$ 0.60	$ 1.53	$ 1.43

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in millions)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
Net income	$ 646.5	$ 553.3	$ 1,453.2	$ 1,308.6
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instruments:				
Changes in fair value of cash flow hedges	(32.8)	34.1	(42.0)	(13.5)
Reclassification of losses (gains) to net income	14.9	(7.2)	30.9	0.1
Interest rate derivative instruments:				
Changes in fair value of cash flow hedges	--	--	--	6.7
Reclassification of losses to net income	8.0	7.8	15.9	13.7
Total cash flow hedges	(9.9)	34.7	4.8	7.0
Other	--	0.4	--	0.4
Total other comprehensive income (loss)	(9.9)	35.1	4.8	7.4
Comprehensive income	636.6	588.4	1,458.0	1,316.0
Comprehensive income attributable to noncontrolling interests	(8.8)	(0.8)	(16.7)	(2.6)
Comprehensive income attributable to limited partners	$ 627.8	$ 587.6	$ 1,441.3	$ 1,313.4

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)

	For the Six Months Ended June 30, 2014	For the Six Months Ended June 30, 2013
Operating activities:		
Net income	$ 1,453.2	$ 1,308.6
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	651.0	599.8
Non-cash asset impairment charges (see Note 4)	12.5	38.1
Equity in income of unconsolidated affiliates	(106.8)	(82.1)
Distributions received from unconsolidated affiliates	157.1	119.3
Net gains attributable to asset sales and insurance recoveries (see Note 16)	(96.4)	(58.2)
Deferred income tax expense	0.6	14.8
Changes in fair market value of derivative instruments	(6.2)	(1.2)
Net effect of changes in operating accounts (see Note 16)	(198.6)	(409.2)
Other operating activities	5.5	1.0
Net cash flows provided by operating activities	1,871.9	1,530.9
Investing activities:		
Capital expenditures	(1,186.4)	(1,447.3)
Contributions in aid of construction costs	13.9	14.9
Decrease (increase) in restricted cash	8.9	(22.0)
Investments in unconsolidated affiliates	(498.8)	(547.9)
Proceeds from asset sales and insurance recoveries (see Note 16)	113.2	199.2
Other investing activities	(5.7)	0.5
Cash used in investing activities	(1,554.9)	(1,802.6)
Financing activities:		
Borrowings under debt agreements	4,182.8	7,064.5
Repayments of debt	(3,161.3)	(6,281.6)
Debt issuance costs	(18.1)	(23.7)
Monetization of interest rate derivative instruments (see Note 4)	--	(168.8)
Cash distributions paid to limited partners (see Note 10)	(1,288.4)	(1,171.9)
Cash payments made in connection with distribution equivalent rights	(1.2)	--
Cash distributions paid to noncontrolling interests	(19.7)	(4.7)
Cash contributions from noncontrolling interests (see Note 10)	4.0	95.9
Net cash proceeds from the issuance of common units	223.3	835.4
Other financing activities	(53.3)	(44.2)
Cash provided by (used in) financing activities	(131.9)	300.9
Net change in cash and cash equivalents	185.1	29.2
Cash and cash equivalents, January 1	56.9	16.1
Cash and cash equivalents, June 30	$ 242.0	$ 45.3

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
(See Note 10 for Unit History, Accumulated Other Comprehensive Income (Loss) and Noncontrolling Interests)
(Dollars in millions)

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2013	$ 15,573.8	$ (359.0)	$ 225.6	$ 15,440.4
Net income	1,436.5	--	16.7	1,453.2
Cash distributions paid to limited partners	(1,288.4)	--	--	(1,288.4)
Cash payments made in connection with distribution equivalent rights	(1.2)	--	--	(1.2)
Cash distributions paid to noncontrolling interests	--	--	(19.7)	(19.7)
Cash contributions from noncontrolling interests	--	--	4.0	4.0
Net cash proceeds from the issuance of common units	223.3	--	--	223.3
Amortization of fair value of equity-based awards	39.9	--	--	39.9
Cash flow hedges	--	4.8	--	4.8
Other	(53.1)	--	(0.8)	(53.9)
Balance, June 30, 2014	$ 15,930.8	$ (354.2)	$ 225.8	$ 15,802.4

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2012	$ 13,558.1	$ (370.4)	$ 108.3	$ 13,296.0
Net income	1,306.0	--	2.6	1,308.6
Cash distributions paid to limited partners	(1,171.9)	--	--	(1,171.9)
Cash distributions paid to noncontrolling interests	--	--	(4.7)	(4.7)
Cash contributions from noncontrolling interests	--	--	95.9	95.9
Net cash proceeds from the issuance of common units	835.4	--	--	835.4
Amortization of fair value of equity-based awards	35.6	--	--	35.6
Cash flow hedges	--	7.0	--	7.0
Other	(44.3)	0.4	(5.2)	(49.1)
Balance, June 30, 2013	$ 14,518.9	$ (363.0)	$ 196.9	$ 14,352.8

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

With the exception of per unit amounts, or as noted within the context of each disclosure, the dollar amounts presented in the tabular data within these disclosures are stated in millions of dollars.

KEY REFERENCES USED IN THESE
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Unless the context requires otherwise, references to "we," "us," "our," "Enterprise" or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise, and its consolidated subsidiaries, through which Enterprise Products Partners L.P. conducts its business. Enterprise is managed by its general partner, Enterprise Products Holdings LLC ("Enterprise GP"), which is a wholly owned subsidiary of Dan Duncan LLC, a privately held Texas limited liability company.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director and Chairman of the Board of Enterprise GP; (ii) Dr. Ralph S. Cunningham; and (iii) Richard H. Bachmann. Each of the DD LLC Trustees also currently serves as one of the three managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company, a privately held Texas corporation, and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Williams, who also serves as Chairman of EPCO; (ii) Dr. Cunningham, who also serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who also serves as the President and Chief Executive Officer ("CEO") of EPCO. Each of the EPCO Trustees is also a director of EPCO.

In addition to owning our general partner, privately held affiliates of EPCO owned approximately 36.4% of our limited partner interests at June 30, 2014.

References to "TEPPCO" mean TEPPCO Partners, L.P. prior to its merger with one of our wholly owned subsidiaries in October 2009.

Note 1. Partnership Operations and Organization

General

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products.

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals (including liquefied petroleum gas or "LPG"); crude oil gathering, transportation, storage and terminals; offshore production platforms; petrochemical and refined products transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our assets include approximately 51,000 miles of onshore and offshore pipelines; 200 million barrels ("MMBbls") of storage capacity for NGLs, petrochemicals, refined products and crude oil; and 14 billion cubic feet ("Bcf") of natural gas storage capacity. In addition, our asset portfolio includes 24 natural gas processing plants, 22 NGL and propylene fractionators, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and LPG export terminals, and octane enhancement and high-purity isobutylene production facilities.

We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services.

We are 100% owned by our limited partners from an economic perspective. We are managed and controlled by Enterprise GP, which has a non-economic general partner interest in us. We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates under the collective common control of the DD LLC Trustees and the EPCO Trustees. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. See Note 12 for information regarding the ASA and other related party matters.

Note 2. General Accounting Matters

Our results of operations for the three and six months ended June 30, 2014 are not necessarily indicative of results expected for the full year of 2014. In our opinion, the accompanying Unaudited Condensed Consolidated Financial Statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe the disclosures in these financial statements are adequate and make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC").

These Unaudited Condensed Consolidated Financial Statements and Notes thereto should be read in conjunction with the Audited Consolidated Financial Statements and Notes thereto included in our annual report on Form 10-K for the year ended December 31, 2013 (the "2013 Form 10-K") filed with the SEC on March 3, 2014.

See Note 18 for information regarding a two-for-one common unit split announced on July 15, 2014. All per unit amounts and number of units outstanding in these Unaudited Condensed Consolidated Financial Statements and Notes thereto are presented on a pre-split basis.

Contingencies

Certain conditions may exist as of the date our consolidated financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the need for accounting recognition or disclosure of these contingencies, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in such proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

We accrue an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when it is believed to be only reasonably possible or remote.

For contingencies where an unfavorable outcome is reasonably possible and the impact would be material, we disclose the nature of the contingency and, if feasible, an estimate of the possible loss or range of loss.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. See Note 14 for additional information regarding our contingencies.

Derivative Instruments

We use derivative instruments such as futures, swaps, options, forward contracts and other arrangements to manage price risks associated with inventories, firm commitments, interest rates, foreign currencies and certain anticipated future commodity transactions. To qualify for hedge accounting, the hedged item must expose us to risk and the related derivative instrument must reduce the exposure to that risk and meet specific hedge documentation requirements related to designation dates, expectations for hedge effectiveness and the probability that hedged future transactions will occur as forecasted. We formally designate derivative instruments as hedges and document and assess their effectiveness at inception of the hedge and on a monthly basis thereafter. Forecasted transactions are evaluated for the probability of occurrence and are periodically back-tested once the forecasted period has passed to determine whether similarly forecasted transactions are probable of occurring in the future.

For certain physical forward commodity derivative contracts, we apply the normal purchase/normal sale exception, whereby changes in the mark-to-market values of such contracts are not recognized in income. As a result, the revenues and expenses associated with such physical transactions are recognized during the period when volumes are physically delivered or received. Physical forward commodity contracts subject to this exception are evaluated for the probability of future delivery and are periodically back-tested once the forecasted period has passed to determine whether similar forward contracts are probable of physical delivery in the future. See Note 4 for additional information regarding our derivative instruments.

Estimates

Preparing our consolidated financial statements in conformity with U.S. GAAP requires us to make estimates that affect amounts presented in the financial statements. Our most significant estimates relate to (i) the useful lives and depreciation/amortization methods used for fixed and identifiable intangible assets; (ii) measurement of fair value and projections used in impairment testing of fixed and intangible assets (including goodwill); (iii) contingencies; and (iv) revenue and expense accruals.

Actual results could differ materially from our estimates. On an ongoing basis, we review our estimates based on currently available information. Any changes in the facts and circumstances underlying our estimates may require us to update such estimates, which could have a material impact on our consolidated financial statements.

Recent Accounting Developments

In May 2014, the Financial Accounting Standards Board ("FASB") and the International Accounting Standards Board finished their joint project to converge U.S. GAAP and International Financial Reporting Standards in the area of revenue recognition. The resulting accounting standards update eliminates the transaction- and industry-specific revenue recognition guidance under current U.S. GAAP and replaces it with a principles based approach for determining revenue recognition.

The core principle in the new guidance is that a company should recognize revenue in a manner that depicts the transfer of goods or services to customers in an amount that reflects the consideration the company expects to receive for those goods or services. In order to apply this core principle, companies will apply the following five steps in determining the amount of revenues to recognize:

§ identify the contract;

§ identify the performance obligations in the contract;

§ determine the transaction price;

§ allocate the transaction price to the performance obligations in the contract; and

§ recognize revenue when (or as) the performance obligation is satisfied.

Each of these steps involves judgment and an analysis of the contract's terms and conditions.

We are continuing to evaluate this recently issued accounting guidance; therefore, we are currently not in a position to estimate its impact on our consolidated financial statements. The effective date of the new standard is January 1, 2017. At present, we expect to adopt the new standard using the modified retrospective method. This modified approach allows us to apply the new standard to (i) all new contracts after the effective date and (ii) all existing contracts as of the effective date through a cumulative adjustment to equity. Consolidated revenues for periods prior to the effective date would not be retrospectively adjusted.

Restricted Cash

Restricted cash represents amounts held in segregated bank accounts by our clearing brokers as margin in support of our commodity derivative instruments portfolio and related physical purchases and sales of natural gas, crude oil, refined products and NGLs. Additional cash may be restricted to maintain our commodity derivative instruments portfolio as prices fluctuate or deposit requirements change. At June 30, 2014 and December 31, 2013, our restricted cash amounts were $56.7 million and $65.6 million, respectively. See Note 4 for information regarding our derivative instruments and hedging activities.

Note 3. Equity-based Awards

An allocated portion of the fair value of EPCO's equity-based awards is charged to us under the ASA. The following table summarizes compensation expense we recognized in connection with equity-based awards for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Equity-classified awards:				
Restricted common unit awards	$ 9.0	$ 18.3	$ 20.6	$ 34.9
Unit option awards	--	0.2	--	0.6
Phantom unit awards	13.6	--	19.4	--
Liability-classified awards	0.2	0.1	0.3	0.3
Total	$ 22.8	$ 18.6	$ 40.3	$ 35.8

The fair value of equity-classified awards is amortized to earnings over the requisite service or vesting period. Equity-classified awards are expected to result in the issuance of common units upon vesting. Compensation expense for liability-classified awards is recognized over the requisite service or vesting period based on the fair value of the award remeasured at each reporting date. Liability-classified awards are settled in cash upon vesting.

At June 30, 2014, EPCO's significant long-term incentive plans applicable to us were the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") and the 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) ("2008 Plan"). Up to 7,000,000 of our common units may be issued as awards under the 1998 Plan. The maximum number of common units available for issuance under the 2008 Plan was 12,500,000 at June 30, 2014. This amount will automatically increase under the terms of the 2008 Plan by 2,500,000 common units on January 1, 2015 and will continue to automatically increase annually on January 1 thereafter during the term of the 2008 Plan; provided, however, that in no event shall the maximum aggregate number exceed 35,000,000 common units. After giving effect to awards granted under the 1998 Plan and 2008 Plan through June 30, 2014, a total of 1,340,885 and 6,388,498 additional common units could be issued under these plans, respectively.

Restricted Common Unit Awards

Restricted common unit awards allow recipients to acquire our common units (at no cost to the recipient apart from fulfilling service and other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. Restricted common unit awards generally vest at a rate of 25% per year beginning one year after the grant date and are non-vested until the required service periods expire. Restricted common units are included in the number of common units outstanding as presented on our Unaudited Condensed Consolidated Balance Sheets.

The following table presents information regarding restricted common unit awards for the period indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted common units at December 31, 2013	3,610,607	$ 51.66
Vested	(1,276,762)	$ 47.81
Forfeited	(115,250)	$ 52.49
Restricted common units at June 30, 2014	2,218,595	$ 53.84

(1) Determined by dividing the aggregate grant date fair value of awards (before an allowance for forfeitures) by the number of awards issued.

Each recipient of a restricted common unit award is entitled to nonforfeitable cash distributions equal to the product of the number of restricted common units outstanding for the participant and the cash distribution per unit paid by Enterprise to its common unitholders. These distributions are included in "Cash distributions paid to limited partners" as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.

The following table presents supplemental information regarding our restricted common unit awards for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Cash distributions paid to restricted common unitholders	$ 1.6	$ 3.0	$ 4.1	$ 5.6
Total intrinsic value of restricted common unit awards that vested during period	$ 2.7	$ 54.0	$ 84.1	$ 106.4

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $47.1 million at June 30, 2014, of which our allocated share of the cost is currently estimated to be $42.2 million. Due to the graded vesting provisions of these awards, we expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 1.7 years.

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options denominated in the common units of Enterprise Products Partners L.P. In general, unit option awards have a vesting period of four years from the date of grant and expire at the end of the calendar year following the year of vesting (e.g., an option vesting on May 29, 2013 will expire on December 31, 2014). However, unit option awards only become exercisable at certain times during the calendar year following the year in which they vest (typically the months of February, May, August and November).

The following table presents unit option award activity for the period indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Unit option awards at December 31, 2013	2,025,000	$ 26.49	1.3	$ 57.0
Exercised	(1,360,000)	$ 23.66		
Forfeited	(30,000)	$ 32.27		
Unit option awards at June 30, 2014	635,000	$ 32.27	1.5	$ 29.2

(1) Aggregate intrinsic value reflects fully vested unit option awards at the date indicated.
(2) None of the unit option awards outstanding at June 30, 2014 and December 31, 2013 were exercisable as of such dates, respectively.

In order to fund its unit option award-related obligations, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit option awards, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The following table presents supplemental information regarding unit option awards during the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Total intrinsic value of unit option awards exercised during period	$ 2.8	$ 3.4	$ 57.5	$ 19.8
Cash received from EPCO in connection with the exercise of unit option awards	1.6	2.0	33.4	11.5
Unit option award-related cash reimbursements to EPCO	2.8	3.4	57.5	19.8

As of June 30, 2014, all compensation expense related to unit option awards had been recognized.

Phantom Unit Awards

Phantom unit awards allow recipients to acquire our common units (at no cost to the recipient apart from fulfilling service and other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. Phantom unit awards generally vest at a rate of 25% per year beginning one year after the grant date and are non-vested until the required service periods expire.

At June 30, 2014, substantially all of our phantom unit awards are expected to result in the issuance of common units upon vesting; therefore, the applicable awards are accounted for as equity-classified awards. Compensation expense attributable to these awards is based on the grant date fair value of the award, net of an allowance for estimated forfeitures, amortized over the requisite service or vesting period. The grant date fair value of a phantom unit award is based on the market price per unit of Enterprise's common units on the date of grant. These awards were first issued in February 2014.

The following table presents phantom unit award activity for the period indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Phantom unit awards at December 31, 2013	--	$ --
Granted (2)	1,737,945	$ 66.11
Vested	(15,800)	$ 66.08
Forfeited	(32,070)	$ 66.08
Phantom unit awards at June 30, 2014	1,690,075	$ 66.11

(1) Determined by dividing the aggregate grant date fair value of awards (before an allowance for forfeitures) by the number of awards issued.
(2) The aggregate grant date fair value of phantom unit awards issued during 2014 was $114.9 million based on a grant date market price of our common units ranging from $66.08 to $74.55 per unit. An estimated annual forfeiture rate of 3.4% was applied to these awards.

Our long-term incentive plans provide for the issuance of distribution equivalent rights ("DERs") in connection with phantom unit awards. A DER entitles the participant to nonforfeitable cash payments equal to the product of the number of phantom unit awards outstanding for the participant and the cash distribution per common unit paid by Enterprise to its common unitholders. Cash payments made in connection with DERs are charged to partners' equity when the phantom unit award is expected to result in the issuance of common units; otherwise, such amounts are expensed.

The following table presents supplemental information regarding our phantom unit awards and DERs for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Cash payments made in connection with DERs	$ 1.2	$ --	$ 1.2	$ --
Total intrinsic value of phantom unit awards that vested during period	$ 1.2	$ --	$ 1.2	$ --

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was $84.2 million at June 30, 2014, of which our allocated share of the cost is currently estimated to be $77.4 million. Due to the graded vesting provisions of these awards, we expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.3 years.

Note 4. Derivative Instruments, Hedging Activities and Fair Value Measurements

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with assets, liabilities and certain anticipated future transactions, we use derivative instruments such as futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. The following table summarizes our portfolio of interest rate swaps at June 30, 2014:

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes AA	10 fixed-to-floating swaps	$ 750.0	1/2011 to 2/2016	3.2% to 1.2%	Fair value hedge
Undesignated swaps	6 floating-to-fixed swaps	$ 600.0	5/2010 to 7/2014	0.2% to 2.0%	Mark-to-market

In July 2014, six undesignated floating-to-fixed swaps having an aggregate notional amount of $600.0 million, that were outstanding at June 30, 2014, expired. These swaps were accounted for as mark-to-market instruments with changes in fair value recorded in "Interest expense" on our Unaudited Condensed Statements of Consolidated Operations.

In connection with the issuance of Senior Notes II and HH in March 2013, we settled 16 forward starting swaps having an aggregate notional amount of $1.0 billion, that were outstanding at December 31, 2012, which resulted in cash losses totaling $168.8 million. These losses are a component of accumulated other comprehensive loss and are being amortized to earnings (as an increase in interest expense) over the forecasted hedge period of ten years using the effective interest method.

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, refined products and petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps, basis swaps and option contracts. The following table summarizes our portfolio of commodity derivative instruments outstanding at June 30, 2014 (volume measures as noted):

	Volume (1)		**Accounting**
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	2.2	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	0.6	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	0.1	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	1.6	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities (Bcf)	3.3	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	6.2	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	7.6	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.6	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.0	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.2	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	3.3	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	5.0	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (4,5)	73.1	12.6	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	13.2	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is March 2015, August 2014 and October 2016, respectively.
(3) Forecasted sales of NGL volumes under natural gas processing exclude 0.6 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.
(4) Current volumes include 37.7 Bcf of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
(5) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

At June 30, 2014, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging the fair value of commodity products held in inventory, (iii) hedging natural gas processing margins, and (iv) hedging octane enhancement margins.

Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items

The following table provides a balance sheet overview of our derivative assets and liabilities at the dates indicated:

	Asset Derivatives				Liability Derivatives			
	June 30, 2014		December 31, 2013		June 30, 2014		December 31, 2013	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments								
Interest rate derivatives	Other current assets	$ 20.4	Other current assets	$ 20.2	Other current liabilities	$ --	Other current liabilities	$ --
Interest rate derivatives	Other assets	6.9	Other assets	12.4	Other liabilities	--	Other liabilities	--
Total interest rate derivatives		27.3		32.6		--		--
Commodity derivatives	Other current assets	35.7	Other current assets	30.9	Other current liabilities	61.9	Other current liabilities	46.5
Commodity derivatives	Other assets	--	Other assets	--	Other liabilities	--	Other liabilities	0.3
Total commodity derivatives		35.7		30.9		61.9		46.8
Total derivatives designated as hedging instruments		$ 63.0		$ 63.5		$ 61.9		$ 46.8
Derivatives not designated as hedging instruments								
Interest rate derivatives	Other current assets	$ --	Other current assets	$ --	Other current liabilities	$ 2.6	Other current liabilities	$ 7.8
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	--	Other liabilities	--
Total interest rate derivatives		--		--		2.6		7.8
Commodity derivatives	Other current assets	7.5	Other current assets	7.6	Other current liabilities	4.0	Other current liabilities	5.5
Commodity derivatives	Other assets	0.9	Other assets	2.8	Other liabilities	0.3	Other liabilities	2.8
Total commodity derivatives		8.4		10.4		4.3		8.3
Total derivatives not designated as hedging instruments		$ 8.4		$ 10.4		$ 6.9		$ 16.1

Certain of our commodity derivative instruments are subject to master netting arrangements or similar agreements. The following tables present our derivative instruments subject to such arrangements at the dates indicated:

	Offsetting of Financial Assets and Derivative Assets					
				Gross Amounts Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Financial Instruments	Cash Collateral Received	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)		(v) = (iii) + (iv)
As of June 30, 2014:						
Interest rate derivatives	$ 27.3	$ --	$ 27.3	$ (0.9)	$ --	$ 26.4
Commodity derivatives	44.1	--	44.1	(31.5)	--	12.6
As of December 31, 2013:						
Interest rate derivatives	$ 32.6	$ --	$ 32.6	$ (2.6)	$ --	$ 30.0
Commodity derivatives	41.3	--	41.3	(41.0)	--	0.3

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	Offsetting of Financial Liabilities and Derivative Liabilities					
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet: Financial Instruments	Gross Amounts Not Offset in the Balance Sheet: Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)	(iv)	(v) = (iii) + (iv)
As of June 30, 2014:						
Interest rate derivatives	$ 2.6	$ --	$ 2.6	$ (0.9)	$ --	$ 1.7
Commodity derivatives	66.2	--	66.2	(31.5)	(22.4)	12.3
As of December 31, 2013:						
Interest rate derivatives	$ 7.8	$ --	$ 7.8	$ (2.6)	$ --	$ 5.2
Commodity derivatives	55.1	--	55.1	(41.0)	(9.3)	4.8

Derivative assets and liabilities recorded on our Unaudited Condensed Consolidated Balance Sheets are presented on a gross-basis and determined at the individual transaction level. The tabular presentation above provides a means for comparing the gross amount of derivative assets and liabilities, excluding associated accounts payable and receivable, to the net amount that would likely be receivable or payable under a default scenario based on the existence of rights of offset in the respective derivative agreements. Any cash collateral paid or received is reflected in this table, but only to the extent that it represents variation margins. Any amounts associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from this table.

The following tables present the effect of our derivative instruments designated as fair value hedges on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2014	2013	2014	2013
Interest rate derivatives	Interest expense	$ (2.5)	$ (6.6)	$ (5.4)	$ (10.1)
Commodity derivatives	Revenue	1.3	6.9	0.9	6.2
Total		$ (1.2)	$ 0.3	$ (4.5)	$ (3.9)

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2014	2013	2014	2013
Interest rate derivatives	Interest expense	$ 2.5	$ 6.5	$ 5.4	$ 9.9
Commodity derivatives	Revenue	(1.0)	(4.9)	(2.4)	(11.6)
Total		$ 1.5	$ 1.6	$ 3.0	$ (1.7)

With respect to our derivative instruments designated as fair value hedges, amounts attributable to ineffectiveness and those excluded from the assessment of hedge effectiveness were not material to our Unaudited Condensed Consolidated Financial Statements during the periods presented.

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The following tables present the effect of our derivative instruments designated as cash flow hedges on our Unaudited Condensed Statements of Consolidated Operations and Unaudited Condensed Statements of Consolidated Comprehensive Income for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income (Loss) on Derivative (Effective Portion)			
	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Interest rate derivatives	$ --	$ --	$ --	$ 6.7
Commodity derivatives – Revenue (1)	(32.9)	34.1	(43.6)	(13.5)
Commodity derivatives – Operating costs and expenses (1)	0.1	--	1.6	--
Total	$ (32.8)	$ 34.1	$ (42.0)	$ (6.8)

(1) The fair value of these derivative instruments will be reclassified to their respective locations on the Unaudited Condensed Statement of Consolidated Operations upon settlement of the underlying derivative transactions, as appropriate.

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) to Income (Effective Portion)			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2014	2013	2014	2013
Interest rate derivatives	Interest expense	$ (8.0)	$ (7.8)	$ (15.9)	$ (13.7)
Commodity derivatives	Revenue	(15.4)	7.2	(32.3)	(0.5)
Commodity derivatives	Operating costs and expenses	0.5	--	1.4	0.4
Total		$ (22.9)	$ (0.6)	$ (46.8)	$ (13.8)

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2014	2013	2014	2013
Commodity derivatives	Revenue	$ 0.1	$ (0.1)	$ (0.1)	$ (0.1)
Commodity derivatives	Operating costs and expenses	(0.1)	--	0.1	--
Total		$ --	$ (0.1)	$ --	$ (0.1)

Over the next twelve months, we expect to reclassify $34.0 million of losses attributable to interest rate derivative instruments from accumulated other comprehensive loss to earnings as an increase in interest expense. Likewise, we expect to reclassify $25.7 million of net losses attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings, $26.8 million as a decrease in revenue and $1.1 million as a decrease in operating costs and expenses.

The following table presents the effect of our derivative instruments not designated as hedging instruments on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

Derivatives Not Designated as Hedging Instruments	Location	Gain (Loss) Recognized in Income on Derivative			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2014	2013	2014	2013
Interest rate derivatives	Interest expense	$ --	$ (0.2)	$ (0.1)	$ (0.1)
Commodity derivatives	Revenue	(6.6)	14.2	(27.6)	8.9
Total		$ (6.6)	$ 14.0	$ (27.7)	$ 8.8

Fair Value Measurements

Our fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk, in the principal market of the asset or liability at a specified measurement date. Recognized valuation techniques employ inputs such as contractual prices, quoted market prices or rates, operating costs, discount factors and business growth rates. These inputs may be either readily observable, corroborated by market data or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the highest extent possible. Accordingly, we utilize valuation techniques (such as the market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

A three-tier hierarchy has been established that classifies fair value amounts recognized in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy.

Recurring Fair Value Measurements

The following tables set forth, by level within the fair value hierarchy, the carrying values of our financial assets and liabilities at June 30, 2014 and December 31, 2013. These assets and liabilities are measured on a recurring basis and are classified based on the lowest level of input used to estimate their fair value. Our assessment of the relative significance of such inputs requires judgment.

	June 30, 2014 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Carrying Value at June 30, 2014
Financial assets:				
Interest rate derivatives	$ --	$ 27.3	$ --	$ 27.3
Commodity derivatives	18.0	22.0	4.1	44.1
Total	$ 18.0	$ 49.3	$ 4.1	$ 71.4
Financial liabilities:				
Interest rate derivatives	$ --	$ 2.6	$ --	$ 2.6
Commodity derivatives	32.1	32.6	1.5	66.2
Total	$ 32.1	$ 35.2	$ 1.5	$ 68.8

	December 31, 2013 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Carrying Value at December 31, 2013
Financial assets:				
Interest rate derivatives	$ --	$ 32.6	$ --	$ 32.6
Commodity derivatives	17.2	20.2	3.9	41.3
Total	$ 17.2	$ 52.8	$ 3.9	$ 73.9
Financial liabilities:				
Interest rate derivatives	$ --	$ 7.8	$ --	$ 7.8
Commodity derivatives	30.8	23.6	0.7	55.1
Total	$ 30.8	$ 31.4	$ 0.7	$ 62.9

The following table sets forth a reconciliation of changes in the fair values of our recurring Level 3 financial assets and liabilities on a combined basis for the periods indicated:

	Location	For the Six Months Ended June 30, 2014	For the Six Months Ended June 30, 2013
Financial asset (liability) balance, net, January 1		$ 3.2	$ (1.5)
Total gains (losses) included in:			
Net income (1)	Revenue	4.6	(0.6)
Settlements	Revenue	(0.1)	1.5
Financial asset (liability) balance, net, March 31		7.7	(0.6)
Total gains (losses) included in:			
Net income (1)	Revenue	(3.3)	(0.2)
Settlements	Revenue	(1.8)	0.6
Financial asset (liability) balance, net, June 30 (2)		$ 2.6	$ (0.2)

(1) There were $5.0 million and $0.5 million of unrealized losses included in these amounts for the three and six months ended June 30, 2014, respectively. There were unrealized gains of $0.4 million and $1.3 million included in these amounts for the three and six months ended June 30, 2013, respectively.
(2) There were no transfers into or out of Level 3 during the three or six months ended June 30, 2014 and 2013.

The following table provides quantitative information about our recurring Level 3 fair value measurements at June 30, 2014:

	Fair Value: Financial Assets	Fair Value: Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Crude oil	$ 4.1	$ 1.5	Discounted cash flow	Forward commodity prices	$94.16-$106.21/barrel

We believe forward commodity prices are the most significant unobservable inputs in determining our Level 3 recurring fair value measurements at June 30, 2014. In general, changes in the price of the underlying commodity increases or decreases the fair value of a commodity derivative depending on whether the derivative was purchased or sold. We generally expect changes in the fair value of our derivative instruments to be offset by corresponding changes in the fair value of our hedged exposures.

Nonrecurring Fair Value Measurements

The following table summarizes our non-cash impairment charges by segment during each of the periods indicated:

	For the Three Months Ended June 30, 2014	For the Three Months Ended June 30, 2013	For the Six Months Ended June 30, 2014	For the Six Months Ended June 30, 2013
NGL Pipelines & Services	$ 2.8	$ 8.7	$ 5.4	$ 9.7
Onshore Natural Gas Pipelines & Services	0.1	--	0.3	--
Onshore Crude Oil Pipelines & Services	0.8	16.6	1.8	16.6
Petrochemical & Refined Products Services	--	1.8	5.0	11.8
Total	$ 3.7	$ 27.1	$ 12.5	$ 38.1

These impairment charges are a component of "Operating costs and expenses" on our Unaudited Condensed Statements of Consolidated Operations.

Our non-cash asset impairment charges for the six months ended June 30, 2014 primarily relate to the abandonment of assets classified as property, plant and equipment. The following table summarizes our non-recurring fair value measurements for the six months ended June 30, 2014:

		Fair Value Measurements Using			
	Carrying Value at June 30, 2014	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Impairment of long-lived assets disposed of other than by sale	$ --	$ --	$ --	$ --	$ 7.5
Impairment of long-lived assets to be disposed of by sale	0.1	--	--	0.1	5.0
Total					$ 12.5

During the six months ended June 30, 2013, we recorded $38.1 million of non-cash asset impairment charges primarily due to the abandonment of assets classified as property, plant and equipment. Of this amount, $16.6 million relates to the abandonment of certain crude oil pipeline segments in Texas and Oklahoma, $10.0 million relates to the abandonment of certain refined products terminal and storage assets located in southeast Texas, and $6.3 million relates to the abandonment of an NGL storage cavern in Arizona. The following table summarizes our non-recurring fair value measurements for the six months ended June 30, 2013:

		Fair Value Measurements Using			
	Carrying Value at June 30, 2013	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Impairment of long-lived assets disposed of other than by sale	$ --	$ --	$ --	$ --	$ 29.8
Impairment of long-lived assets held and used	6.3	--	--	6.3	4.2
Impairment of long-lived assets to be disposed of by sale	34.6	33.8	--	0.8	4.1
Total					$ 38.1

Other Fair Value Information

The carrying amounts of cash and cash equivalents (including restricted cash balances), accounts receivable, commercial paper notes and accounts payable approximate their fair values based on their short-term nature. The estimated total fair value of our fixed-rate debt obligations was $20.35 billion and $18.4 billion at June 30, 2014 and December 31, 2013, respectively. The aggregate carrying value of these debt obligations was $18.38 billion and $17.36 billion at June 30, 2014 and December 31, 2013, respectively. These values are based on quoted market prices for such debt or debt of similar terms and maturities (Level 2), our credit standing and the credit standing of our counterparties. Changes in market rates of interest affect the fair value of our fixed-rate debt. The carrying values of our variable-rate long-term debt obligations approximate their fair values since the associated interest rates are market-based. We do not have any long-term investments in debt or equity securities recorded at fair value.

Note 5. Inventories

Our inventory amounts by product type were as follows at the dates indicated:

	June 30, 2014	December 31, 2013
NGLs	$ 617.8	$ 593.8
Petrochemicals and refined products	300.8	395.1
Crude oil	368.9	42.6
Natural gas	30.8	61.6
Total	$ 1,318.3	$ 1,093.1

Due to fluctuating commodity prices, we recognize lower of cost or market adjustments when the carrying value of our available-for-sale inventories exceeds their net realizable value. The following table presents our total cost of sales amounts and lower of cost or market adjustments for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Cost of sales (1)	$ 10,705.3	$ 9,458.3	$ 21,758.0	$ 19,150.8
Lower of cost or market adjustments	2.7	7.7	7.9	10.4

(1) Cost of sales is a component of "Operating costs and expenses" as presented on our Unaudited Condensed Statements of Consolidated Operations. Period-to-period fluctuations in these amounts are primarily due to changes in energy commodity prices and sales volumes associated with our marketing activities.

Note 6. Property, Plant and Equipment

The historical costs of our property, plant and equipment and related accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	June 30, 2014	December 31, 2013
Plants, pipelines and facilities (1)	3-45 (6)	$ 29,797.3	$ 27,540.4
Underground and other storage facilities (2)	5-40 (7)	2,134.7	2,101.8
Platforms and facilities (3)	20-31	659.6	659.6
Transportation equipment (4)	3-10	143.6	138.9
Marine vessels (5)	15-30	773.3	744.8
Land		178.1	176.6
Construction in progress		1,463.0	2,655.5
Total		35,149.6	34,017.6
Less accumulated depreciation		7,594.9	7,071.0
Property, plant and equipment, net		$ 27,554.7	$ 26,946.6

(1) Plants, pipelines and facilities include processing plants; NGL, natural gas, crude oil and petrochemical and refined products pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment and related assets.
(2) Underground and other storage facilities include underground product storage caverns; above ground storage tanks; water wells and related assets.
(3) Platforms and facilities include offshore platforms and related facilities and other associated assets located in the Gulf of Mexico.
(4) Transportation equipment includes tractor-trailer tank trucks and other vehicles and similar assets used in our operations.
(5) Marine vessels include tow boats, barges and related equipment used in our marine transportation business.
(6) In general, the estimated useful lives of major assets within this category are: processing plants, 20-35 years; pipelines and related equipment, 5-45 years; terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-40 years; and laboratory and shop equipment, 5-35 years.
(7) In general, the estimated useful lives of assets within this category are: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Depreciation expense (1)	$ 271.0	$ 250.8	$ 538.9	$ 496.2
Capitalized interest (2)	17.7	35.7	36.2	67.3

(1) Depreciation expense is a component of "Costs and expenses" as presented on our Unaudited Condensed Statements of Consolidated Operations.
(2) We capitalize interest costs incurred on funds used to construct property, plant and equipment while the asset is in its construction phase. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset's estimated useful life as a component of depreciation expense. When capitalized interest is recorded, it reduces interest expense from what it would be otherwise.

In March 2013, we sold the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, along with a related storage cavern, for cash proceeds of $86.9 million. As a result, net income for the six months ended June 30, 2013 includes a $52.5 million gain attributable to the sale of these assets. The Seminole Pipeline remains connected to our Mont Belvieu complex through a newly constructed NGL pipeline that we own.

In April 2013, we sold certain lubrication oil and specialty chemical distribution assets for cash proceeds of $35.3 million. As a result, net income for the three and six months ended June 30, 2013 includes a $6.7 million gain from the sale of these assets.

Asset Retirement Obligations

Property, plant and equipment at June 30, 2014 and December 31, 2013 includes $32.3 million and $37.4 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents information regarding our asset retirement obligations ("AROs") during the six months ended June 30, 2014:

ARO liability balance, December 31, 2013	$ 90.2
Liabilities incurred	0.1
Liabilities settled	(2.4)
Revisions in estimated cash flows	(0.2)
Accretion expense	3.0
ARO liability balance, June 30, 2014	$ 90.7

The following table presents our forecast of accretion expense for the periods indicated:

Remainder of 2014	2015	2016	2017	2018
$ 3.1	$ 6.3	$ 6.5	$ 7.0	$ 7.5

Certain of our unconsolidated affiliates have AROs recorded at June 30, 2014 and December 31, 2013 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our consolidated financial statements.

Note 7. Investments in Unconsolidated Affiliates

The following table presents our investments in unconsolidated affiliates by business segment at the dates indicated. We account for these investments using the equity method.

	Ownership Interest at June 30, 2014	June 30, 2014	December 31, 2013
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 28.8	$ 27.6
K/D/S Promix, L.L.C.	50%	45.8	45.4
Baton Rouge Fractionators LLC	32.2%	19.6	19.5
Skelly-Belvieu Pipeline Company, L.L.C.	50%	39.5	40.8
Texas Express Pipeline LLC	35%	344.7	339.9
Texas Express Gathering LLC	45%	37.4	37.8
Front Range Pipeline LLC	33.3%	165.1	134.5
Onshore Natural Gas Pipelines & Services:			
White River Hub, LLC	50%	23.6	24.2
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC	50%	1,329.8	940.7
Eagle Ford Pipeline LLC	50%	247.3	224.5
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	37.9	41.7
Cameron Highway Oil Pipeline Company	50%	203.7	207.7
Deepwater Gateway, L.L.C.	50%	81.1	84.5
Neptune Pipeline Company, L.L.C.	25.7%	36.7	38.7
Southeast Keathley Canyon Pipeline Company L.L.C.	50%	163.4	159.2
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	7.1	7.6
Centennial Pipeline LLC ("Centennial")	50%	65.2	60.1
Other	Various	2.6	2.7
Total		$ 2,879.3	$ 2,437.1

The following table presents our equity in income (loss) of unconsolidated affiliates by business segment for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
NGL Pipelines & Services	$ 6.1	$ 3.8	$ 7.5	$ 7.7
Onshore Natural Gas Pipelines & Services	0.9	0.9	1.8	1.9
Onshore Crude Oil Pipelines & Services	42.2	30.1	84.9	66.7
Offshore Pipelines & Services	7.6	8.7	18.7	15.1
Petrochemical & Refined Products Services	(6.5)	(5.9)	(6.1)	(9.3)
Total	$ 50.3	$ 37.6	$ 106.8	$ 82.1

The following table presents our unamortized excess cost amounts by business segment at the dates indicated:

	June 30, 2014	December 31, 2013
NGL Pipelines & Services	$ 27.0	$ 27.7
Onshore Crude Oil Pipelines & Services	17.5	17.8
Offshore Pipelines & Services	9.5	10.0
Petrochemical & Refined Products Services	2.5	2.6
Total	$ 56.5	$ 58.1

The following table presents our amortization of excess cost amounts by business segment for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
NGL Pipelines & Services	$ 0.4	$ 0.3	$ 0.7	$ 0.6
Onshore Crude Oil Pipelines & Services	0.1	0.2	0.3	0.4
Offshore Pipelines & Services	0.3	0.4	0.5	0.7
Petrochemical & Refined Products Services	0.1	--	0.1	--
Total	$ 0.9	$ 0.9	$ 1.6	$ 1.7

Other

The credit agreements of Poseidon and Centennial restrict their ability to pay cash dividends if a default or event of default (as defined in each credit agreement) has occurred and is continuing at the time such payments are scheduled to be paid. These businesses were in compliance with the terms of their credit agreements at June 30, 2014.

Note 8. Intangible Assets and Goodwill

The following table summarizes our intangible assets by business segment at the dates indicated:

	June 30, 2014			December 31, 2013		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 340.8	$ (174.8)	$ 166.0	$ 340.8	$ (165.7)	$ 175.1
Contract-based intangibles	286.4	(179.4)	107.0	281.3	(171.2)	110.1
Segment total	627.2	(354.2)	273.0	622.1	(336.9)	285.2
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,163.6	(295.5)	868.1	1,163.6	(281.2)	882.4
Contract-based intangibles	466.1	(339.5)	126.6	466.1	(330.7)	135.4
Segment total	1,629.7	(635.0)	994.7	1,629.7	(611.9)	1,017.8
Onshore Crude Oil Pipelines & Services:						
Customer relationship intangibles	10.7	(6.9)	3.8	10.7	(6.3)	4.4
Contract-based intangibles	0.4	(0.3)	0.1	0.4	(0.3)	0.1
Segment total	11.1	(7.2)	3.9	11.1	(6.6)	4.5
Offshore Pipelines & Services:						
Customer relationship intangibles	195.8	(150.1)	45.7	203.9	(150.0)	53.9
Contract-based intangibles	1.2	(0.5)	0.7	1.2	(0.4)	0.8
Segment total	197.0	(150.6)	46.4	205.1	(150.4)	54.7
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.3	(40.8)	63.5	104.3	(38.2)	66.1
Contract-based intangibles	39.9	(6.5)	33.4	39.9	(6.0)	33.9
Segment total	144.2	(47.3)	96.9	144.2	(44.2)	100.0
Total all segments	$ 2,609.2	$ (1,194.3)	$ 1,414.9	$ 2,612.2	$ (1,150.0)	$ 1,462.2

The following table presents the amortization expense of our intangible assets by business segment for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
NGL Pipelines & Services	$ 8.7	$ 9.5	$ 17.3	$ 19.1
Onshore Natural Gas Pipelines & Services	11.5	12.3	23.1	24.7
Onshore Crude Oil Pipelines & Services	0.3	0.4	0.6	0.7
Offshore Pipelines & Services	2.5	2.9	5.1	5.9
Petrochemical & Refined Products Services	1.5	1.6	3.1	3.2
Total	$ 24.5	$ 26.7	$ 49.2	$ 53.6

The following table presents our forecast of amortization expense associated with existing intangible assets for the periods indicated:

Remainder of 2014	2015	2016	2017	2018
$ 45.5	$ 86.0	$ 81.6	$ 86.1	$ 89.5

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. The following table presents changes in the carrying amount of goodwill during the six months ended June 30, 2014:

	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Consolidated Total
Balance at December 31, 2013 (1)	$ 341.2	$ 296.3	$ 305.1	$ 82.1	$ 1,055.3	$ 2,080.0
Reclassification of goodwill	520.0	--	--	--	(520.0)	--
Goodwill related to the sale of assets	--	--	--	(0.1)	--	(0.1)
Balance at June 30, 2014 (1)	$ 861.2	$ 296.3	$ 305.1	$ 82.0	$ 535.3	$ 2,079.9

(1) The total carrying amount of goodwill at June 30, 2014 and December 31, 2013 is net of $1.3 million of accumulated impairment charges. No goodwill impairment charges were recorded during the six months ended June 30, 2014.

In January 2014, our Appalachia-to-Texas Express ("ATEX") ethane pipeline commenced operations. In addition to construction of new assets, this project involved repurposing portions of the TE Products Pipeline to accommodate the southbound delivery of ethane produced from the Marcellus and Utica Shales to the U.S. Gulf Coast. The repurposed assets were reclassified from the Petrochemical & Refined Products Services business segment to the NGL Pipelines & Services business segment in January 2014 when the ATEX pipeline commenced operations. Pipeline assets that continue to be utilized by the TE Products Pipeline in the northbound delivery of refined products and other hydrocarbons from the U.S. Gulf Coast remain in the Petrochemical & Refined Products Services business segment.

In total, the carrying value of the fixed assets at January 1, 2014 that were transferred from the TE Products Pipeline to the ATEX pipeline was $73.7 million. Based on the relative fair values of the assets involved, we also transferred $520.0 million of goodwill from the Petrochemical & Refined Products Services business segment to the NGL Pipelines & Services business segment. The relative fair values of the segment assets were determined based on assumptions regarding the future economic prospects of the ATEX pipeline versus the other assets that would remain in the associated reporting unit. These assumptions included: (i) discrete financial forecasts for the pipelines and related businesses contained within the reporting unit, which, in turn, relied on management's estimates of future operating margins, throughput volumes and similar factors; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates. We believe our assumptions are consistent with those that market participants would utilize in estimating the reporting unit's fair value.

Note 9. Debt Obligations

The following table presents our consolidated debt obligations (arranged by company and maturity date) at the dates indicated:

	June 30, 2014	December 31, 2013
EPO senior debt obligations:		
Commercial Paper Notes, fixed-rates	$ --	$ 475.0
Senior Notes O, 9.75% fixed-rate, due January 2014	--	500.0
Senior Notes G, 5.60% fixed-rate, due October 2014	650.0	650.0
Senior Notes I, 5.00% fixed-rate, due March 2015	250.0	250.0
Senior Notes X, 3.70% fixed-rate, due June 2015	400.0	400.0
Senior Notes FF, 1.25% fixed-rate, due August 2015	650.0	650.0
Senior Notes AA, 3.20% fixed-rate, due February 2016	750.0	750.0
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes V, 6.65% fixed-rate, due April 2018	349.7	349.7
$3.5 Billion Multi-Year Revolving Credit Facility, variable-rate, due June 2018	--	--
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
Senior Notes Q, 5.25% fixed-rate, due January 2020	500.0	500.0
Senior Notes Y, 5.20% fixed-rate, due September 2020	1,000.0	1,000.0
Senior Notes CC, 4.05% fixed-rate, due February 2022	650.0	650.0
Senior Notes HH, 3.35% fixed-rate, due March 2023	1,250.0	1,250.0
Senior Notes JJ, 3.90% fixed-rate, due February 2024	850.0	--
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes W, 7.55% fixed-rate, due April 2038	399.6	399.6
Senior Notes R, 6.125% fixed-rate, due October 2039	600.0	600.0
Senior Notes Z, 6.45% fixed-rate, due September 2040	600.0	600.0
Senior Notes BB, 5.95% fixed-rate, due February 2041	750.0	750.0
Senior Notes DD, 5.70% fixed-rate, due February 2042	600.0	600.0
Senior Notes EE, 4.85% fixed-rate, due August 2042	750.0	750.0
Senior Notes GG, 4.45% fixed-rate, due February 2043	1,100.0	1,100.0
Senior Notes II, 4.85% fixed-rate, due March 2044	1,000.0	1,000.0
Senior Notes KK, 5.10% fixed-rate, due February 2045	1,150.0	--
TEPPCO senior debt obligations:		
TEPPCO Senior Notes, 6.65% fixed-rate, due April 2018	0.3	0.3
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	0.4	0.4
Total principal amount of senior debt obligations	16,850.0	15,825.0
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066 (1)	550.0	550.0
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 (2)	285.8	285.8
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068 (3)	682.7	682.7
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067 (2)	14.2	14.2
Total principal amount of senior and junior debt obligations	18,382.7	17,357.7
Other, non-principal amounts	(19.8)	(6.2)
Less current maturities of debt (4)	(1,300.0)	(1,125.0)
Total long-term debt	$ 17,062.9	$ 16,226.5

(1) Fixed rate of 8.375% through August 1, 2016; thereafter, variable rate based on 3-month LIBOR plus 3.7075%.
(2) Fixed rate of 7.0% through September 1, 2017; thereafter, variable rate based on 3-month LIBOR plus 2.7775%.
(3) Fixed rate of 7.034% through January 15, 2018; thereafter, the rate will be the greater of 7.034% or a variable rate based on 3-month LIBOR plus 2.68%.
(4) We expect to refinance the current maturities of our debt obligations at or prior to their maturity.

The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at June 30, 2014 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt					
	Total	Remainder of 2014	2015	2016	2017	2018	After 2018
Senior Notes	$ 16,850.0	$ 650.0	$ 1,300.0	$ 750.0	$ 800.0	$ 350.0	$ 13,000.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	$ 18,382.7	$ 650.0	$ 1,300.0	$ 750.0	$ 800.0	$ 350.0	$ 14,532.7

Apart from those items discussed below and routine fluctuations in the balance of our revolving credit facility and commercial paper notes, there have been no significant changes in the terms or amounts of our consolidated debt obligations since those reported in our 2013 Form 10-K.

Parent-Subsidiary Guarantor Relationships

Enterprise Products Partners L.P. acts as guarantor of the consolidated debt obligations of EPO with the exception of the remaining debt obligations of TEPPCO. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full and unconditional repayment of that obligation.

Issuance of Senior Notes in February 2014

In February 2014, EPO issued $850 million in principal amount of 3.90% senior notes due February 2024 ("Senior Notes JJ") and $1.15 billion in principal amount of 5.10% senior notes due February 2045 ("Senior Notes KK"). Senior Notes JJ were issued at 99.811% of their principal amount and Senior Notes KK were issued at 99.845% of their principal amount. Proceeds from the issuance of Senior Notes JJ and KK were used to repay debt, including amounts then outstanding under EPO's commercial paper program (which EPO used to repay $500.0 million in principal amount of Senior Notes O that matured in January 2014) and for general company purposes.

Enterprise Products Partners L.P. has unconditionally guaranteed Senior Notes JJ and KK on an unsecured and unsubordinated basis. These senior notes rank equal with EPO's existing and future unsecured and unsubordinated indebtedness and are senior to any existing and future subordinated indebtedness of EPO. These senior notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions.

364-Day Credit Agreement Terminated on May 1, 2014

Effective May 1, 2014, EPO elected to terminate its $1.0 billion 364-Day Credit Agreement in advance of the facility's scheduled maturity date of June 18, 2014. No borrowings were made under this variable-rate revolving credit facility since its inception.

Letters of Credit

At June 30, 2014, EPO had $2.5 million of letters of credit outstanding related to operations at our facilities and motor fuel tax obligations.

Lender Financial Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at June 30, 2014.

Information Regarding Variable Interest Rates Paid

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt during the six months ended June 30, 2014:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO $3.5 Billion Multi-Year Revolving Credit Facility	1.13% to 1.14%	1.13%

Note 10. Equity and Distributions

Partners' equity reflects the various classes of limited partner interests (i.e., common units, including restricted common units) that we have outstanding. The following table summarizes changes in the number of Enterprise's outstanding units since December 31, 2013:

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
Number of units outstanding at December 31, 2013	932,074,401	3,610,607	935,685,008
Common units issued in connection with at-the-market program	795,167	--	795,167
Common units issued in connection with DRIP and EUPP	2,519,969	--	2,519,969
Common units issued in connection with the vesting and exercise of unit options	507,054	--	507,054
Common units issued in connection with the vesting of phantom unit awards	9,171	--	9,171
Common units issued in connection with the vesting of restricted common unit awards	1,276,762	(1,276,762)	--
Forfeiture of restricted common unit awards	--	(115,250)	(115,250)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(434,584)	--	(434,584)
Other	8,601	--	8,601
Number of units outstanding at June 30, 2014	936,756,541	2,218,595	938,975,136

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. We have a universal shelf registration statement (the "2013 Shelf") on file with the SEC. The 2013 Shelf allows Enterprise Products Partners L.P. and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. EPO utilized the 2013 Shelf to issue $2.0 billion of senior notes in February 2014 (see Note 9).

We have a registration statement on file with the SEC covering the issuance of up to $1.25 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to this "at-the-market" program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers' transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. During the six months ended June 30, 2014, we sold 795,167 common units under the "at-the-market" program for aggregate gross proceeds of $58.3 million, resulting in net cash proceeds of $57.7 million. During the six months ended June 30, 2013, we sold 3,766,557 common units under the program for aggregate gross proceeds of $228.5 million. After taking into account applicable costs, these transactions resulted in net cash proceeds of $226.5 million, of which $214.2 million was received as of June 30, 2013. After taking into account the aggregate sale price of common units sold under our at-the-market program through June 30, 2014, we have the capacity to issue additional common units under this program up to an aggregate sales price of $1.19 billion.

We also have registration statements on file with the SEC collectively authorizing the issuance of up to 70,000,000 of our common units in connection with a distribution reinvestment plan (or "DRIP"). We issued 2,445,439 common units under our DRIP during the six months ended June 30, 2014, which generated net cash proceeds of $160.4 million. During the six months ended June 30, 2013, we issued 2,359,089 common units, which generated net cash proceeds of $129.8 million. After taking into account the number of common units issued under the DRIP through June 30, 2014, we have the capacity to issue an additional 16,035,439 common units under this plan.

In January 2014, privately held affiliates of EPCO expressed their willingness to consider purchasing through the DRIP a total of $100 million of our common units during 2014. During the six months ended June 30, 2014, these EPCO affiliates reinvested $50.0 million, resulting in the issuance of 761,487 common units under our DRIP (this amount being a component of the total common units issued under the DRIP for the six months ended June 30, 2014). On August 7, 2014, these EPCO affiliates reinvested an additional $25 million through the DRIP.

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of up to 4,000,000 of our common units in connection with an employee unit purchase plan (or "EUPP"). We issued 74,530 common units under our EUPP during the six months ended June 30, 2014, which generated net cash proceeds of $5.2 million. During the six months ended June 30, 2013, we issued 81,695 common units, which generated net cash proceeds of $4.8 million. After taking into account the number of common units issued under the EUPP through June 30, 2014, we may issue an additional 3,638,914 common units under this plan.

The net cash proceeds we received from the issuance of common units during the six months ended June 30, 2014 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and for general company purposes.

Two-for-One Split of Limited Partner Units

On July 15, 2014, we announced that our general partner approved a two-for-one split of our common units. The common unit split will be accomplished by distributing one additional common unit for each common unit outstanding as of the close of business on August 14, 2014. See Note 18 for additional information regarding this subsequent event.

Accumulated Other Comprehensive Loss

The following tables present the components of accumulated other comprehensive income (loss) as reported on our Unaudited Condensed Consolidated Balance Sheets at the dates indicated:

	Gains (Losses) on Cash Flow Hedges			
	Commodity Derivative Instruments	Interest Rate Derivative Instruments	Other	Total
Balance, December 31, 2013	$ (14.7)	$ (347.2)	$ 2.9	$ (359.0)
Other comprehensive income before reclassifications	(42.0)	--	--	(42.0)
Amounts reclassified from accumulated other comprehensive loss	30.9	15.9	--	46.8
Total other comprehensive income (loss)	(11.1)	15.9	--	4.8
Balance, June 30, 2014	$ (25.8)	$ (331.3)	$ 2.9	$ (354.2)

	Gains (Losses) on Cash Flow Hedges			
	Commodity Derivative Instruments	Interest Rate Derivative Instruments	Other	Total
Balance, December 31, 2012	$ 10.1	$ (383.0)	$ 2.5	$ (370.4)
Other comprehensive income before reclassifications	(13.5)	6.7	0.4	(6.4)
Amounts reclassified from accumulated other comprehensive loss	0.1	13.7	--	13.8
Total other comprehensive income (loss)	(13.4)	20.4	0.4	7.4
Balance, June 30, 2013	$ (3.3)	$ (362.6)	$ 2.9	$ (363.0)

The following table presents reclassifications out of accumulated other comprehensive income (loss) into net income during the periods indicated:

	Location	For the Three Months Ended June 30, 2014	For the Three Months Ended June 30, 2013	For the Six Months Ended June 30, 2014	For the Six Months Ended June 30, 2013
Losses (gains) on cash flow hedges:					
Interest rate derivatives	Interest expense	$ 8.0	$ 7.8	$ 15.9	$ 13.7
Commodity derivatives	Revenue	15.4	(7.2)	32.3	0.5
Commodity derivatives	Operating costs and expenses	(0.5)	--	(1.4)	(0.4)
Total		$ 22.9	$ 0.6	$ 46.8	$ 13.8

Noncontrolling Interests

Noncontrolling interests as presented on our Unaudited Condensed Consolidated Financial Statements represent third party ownership interests in joint ventures that we consolidate for financial reporting purposes, including Tri-States NGL Pipeline L.L.C., Independence Hub LLC, Rio Grande Pipeline Company, Wilprise Pipeline Company LLC and Enterprise EF78 LLC.

Cash Distributions

The following table presents Enterprise's declared quarterly cash distribution rates per common unit with respect to the quarter indicated:

	Distribution Per Common Unit	Record Date	Payment Date
2013:			
1st Quarter	$ 0.6700	04/30/13	05/07/13
2nd Quarter	$ 0.6800	07/31/13	08/07/13
2014:			
1st Quarter	$ 0.7100	04/30/14	05/07/14
2nd Quarter	$ 0.7200	07/31/14	08/07/14

As noted previously, on July 15, 2014, we announced that our general partner approved a two-for-one common unit split that will be completed on August 21, 2014 (see Note 18). The common unit split will reduce declared future distributions per common unit (e.g., a $0.72 per unit distribution rate will become a $0.36 per unit distribution rate), but not the total amount of distributions paid since the number of common units outstanding will increase proportionally (i.e., the number of common units outstanding will double).

In November 2010, we completed our merger with Enterprise GP Holdings L.P. (the "Holdings Merger"). In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from us with respect to a certain number of our common units it owns (the "Designated Units"). Distributions paid during 2014 exclude 22,560,000 Designated Units. Distributions to be paid, if any, during 2015 will exclude 17,690,000 Designated Units.

Note 11. Business Segments

We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the types of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our executive management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

In total, gross operating margin represents operating income exclusive of (1) depreciation, amortization and accretion expenses, (2) impairment charges, (3) gains and losses attributable to asset sales and insurance recoveries and (4) general and administrative costs. Gross operating margin includes equity in income of unconsolidated affiliates and non-refundable deferred transportation revenues relating to the make-up rights of committed shippers associated with certain pipelines. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation. Gross operating margin is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-based rates. Our consolidated revenues reflect the elimination of intercompany transactions. Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base.

Segment assets consist of property, plant and equipment, investments in unconsolidated affiliates, intangible assets and goodwill. The carrying values of such amounts are assigned to each segment based on each asset's or investment's principal operations and contribution to the gross operating margin of that particular segment. Since construction-in-progress amounts (a component of property, plant and equipment) generally do not contribute to segment gross operating margin, such amounts are excluded from segment asset totals until the underlying assets are placed in service. Intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate. Substantially all of our plants, pipelines and other fixed assets are located in the U.S.

The following table presents our measurement of non-GAAP total segment gross operating margin for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues	$ 12,520.8	$ 11,149.3	$ 25,430.7	$ 22,532.4
Subtract operating costs and expenses	(11,639.1)	(10,367.2)	(23,519.6)	(20,787.6)
Add equity in income of unconsolidated affiliates	50.3	37.6	106.8	82.1
Add depreciation, amortization and accretion expense amounts not reflected in gross operating margin	312.4	289.7	613.8	566.5
Add impairment charges not reflected in gross operating margin	3.7	27.1	12.5	38.1
Subtract net gains or add net losses attributable to asset sales and insurance recoveries not reflected in gross operating margin	(6.8)	5.7	(96.4)	(58.2)
Add non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	21.9	--	45.2	--
Total segment gross operating margin	$ 1,263.2	$ 1,142.2	$ 2,593.0	$ 2,373.3

The following table presents a reconciliation of total segment gross operating margin to operating income and further to income before income taxes for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Total segment gross operating margin	$ 1,263.2	$ 1,142.2	$ 2,593.0	$ 2,373.3
Adjustments to reconcile total segment gross operating margin to operating income:				
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(312.4)	(289.7)	(613.8)	(566.5)
Subtract impairment charges not reflected in gross operating margin	(3.7)	(27.1)	(12.5)	(38.1)
Add net gains or subtract net losses attributable to asset sales and insurance recoveries not reflected in gross operating margin (see Note 16)	6.8	(5.7)	96.4	58.2
Subtract non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	(21.9)	--	(45.2)	--
Subtract general and administrative costs not reflected in gross operating margin	(47.7)	(45.5)	(100.9)	(95.0)
Operating income	884.3	774.2	1,917.0	1,731.9
Other expense, net	(227.8)	(200.5)	(449.0)	(396.5)
Income before income taxes	$ 656.5	$ 573.7	$ 1,468.0	$ 1,335.4

Information by business segment, together with reconciliations to our consolidated financial statement totals, is presented in the following table:

	Reportable Business Segments						
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:							
Three months ended June 30, 2014	$ 4,019.5	$ 1,034.5	$ 5,865.6	$ 36.6	$ 1,547.3	$ --	$ 12,503.5
Three months ended June 30, 2013	3,504.7	953.0	5,129.5	39.3	1,516.1	--	11,142.6
Six months ended June 30, 2014	9,193.2	2,234.5	10,801.0	71.3	3,077.9	--	25,377.9
Six months ended June 30, 2013	7,455.4	1,827.2	9,922.7	79.8	3,234.7	--	22,519.8
Revenues from related parties:							
Three months ended June 30, 2014	1.7	6.5	6.7	2.4	--	--	17.3
Three months ended June 30, 2013	0.2	4.5	--	2.0	--	--	6.7
Six months ended June 30, 2014	7.5	11.1	29.6	4.6	--	--	52.8
Six months ended June 30, 2013	0.5	8.0	--	4.1	--	--	12.6
Intersegment and intrasegment revenues:							
Three months ended June 30, 2014	3,324.9	295.4	5,634.3	1.3	428.4	(9,684.3)	--
Three months ended June 30, 2013	2,380.4	254.9	2,717.0	4.2	394.2	(5,750.7)	--
Six months ended June 30, 2014	7,185.9	604.8	8,185.0	3.6	865.4	(16,844.7)	--
Six months ended June 30, 2013	5,089.4	511.1	4,741.7	6.2	816.3	(11,164.7)	--
Total revenues:							
Three months ended June 30, 2014	7,346.1	1,336.4	11,506.6	40.3	1,975.7	(9,684.3)	12,520.8
Three months ended June 30, 2013	5,885.3	1,212.4	7,846.5	45.5	1,910.3	(5,750.7)	11,149.3
Six months ended June 30, 2014	16,386.6	2,850.4	19,015.6	79.5	3,943.3	(16,844.7)	25,430.7
Six months ended June 30, 2013	12,545.3	2,346.3	14,664.4	90.1	4,051.0	(11,164.7)	22,532.4
Equity in income (loss) of unconsolidated affiliates:							
Three months ended June 30, 2014	6.1	0.9	42.2	7.6	(6.5)	--	50.3
Three months ended June 30, 2013	3.8	0.9	30.1	8.7	(5.9)	--	37.6
Six months ended June 30, 2014	7.5	1.8	84.9	18.7	(6.1)	--	106.8
Six months ended June 30, 2013	7.7	1.9	66.7	15.1	(9.3)	--	82.1
Gross operating margin:							
Three months ended June 30, 2014	680.9	203.0	184.0	33.6	161.7	--	1,263.2
Three months ended June 30, 2013	544.9	197.7	197.2	39.7	162.7	--	1,142.2
Six months ended June 30, 2014	1,460.9	423.4	343.7	72.9	292.1	--	2,593.0
Six months ended June 30, 2013	1,137.4	388.5	433.6	80.2	333.6	--	2,373.3
Property, plant and equipment, net: (see Note 6)							
At June 30, 2014	11,800.0	8,865.0	1,511.0	1,184.9	2,730.8	1,463.0	27,554.7
At December 31, 2013	9,957.8	8,917.3	1,479.9	1,223.7	2,712.4	2,655.5	26,946.6
Investments in unconsolidated affiliates: (see Note 7)							
At June 30, 2014	680.9	23.6	1,577.1	522.8	74.9	--	2,879.3
At December 31, 2013	645.5	24.2	1,165.2	531.8	70.4	--	2,437.1
Intangible assets, net: (see Note 8)							
At June 30, 2014	273.0	994.7	3.9	46.4	96.9	--	1,414.9
At December 31, 2013	285.2	1,017.8	4.5	54.7	100.0	--	1,462.2
Goodwill: (see Note 8)							
At June 30, 2014	861.2	296.3	305.1	82.0	535.3	--	2,079.9
At December 31, 2013	341.2	296.3	305.1	82.1	1,055.3	--	2,080.0
Segment assets:							
At June 30, 2014	13,615.1	10,179.6	3,397.1	1,836.1	3,437.9	1,463.0	33,928.8
At December 31, 2013	11,229.7	10,255.6	2,954.7	1,892.3	3,938.1	2,655.5	32,925.9

The following table presents additional information regarding our consolidated revenues and costs and expenses for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 3,630.6	$ 3,235.9	$ 8,426.4	$ 6,901.5
Midstream services	390.6	269.0	774.3	554.4
Total	4,021.2	3,504.9	9,200.7	7,455.9
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	787.0	723.9	1,740.2	1,363.4
Midstream services	254.0	233.6	505.4	471.8
Total	1,041.0	957.5	2,245.6	1,835.2
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	5,781.9	5,057.4	10,655.3	9,800.2
Midstream services	90.4	72.1	175.3	122.5
Total	5,872.3	5,129.5	10,830.6	9,922.7
Offshore Pipelines & Services:				
Sales of natural gas	--	0.1	0.2	0.2
Sales of crude oil	2.9	(0.1)	5.0	2.2
Midstream services	36.1	41.3	70.7	81.5
Total	39.0	41.3	75.9	83.9
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,376.6	1,334.2	2,732.8	2,881.4
Midstream services	170.7	181.9	345.1	353.3
Total	1,547.3	1,516.1	3,077.9	3,234.7
Total consolidated revenues	$ 12,520.8	$ 11,149.3	$ 25,430.7	$ 22,532.4
Consolidated costs and expenses				
Operating costs and expenses:				
Cost of sales	$ 10,705.3	$ 9,458.3	$ 21,758.0	$ 19,150.8
Other operating costs and expenses (1)	624.5	586.4	1,231.7	1,090.4
Depreciation, amortization and accretion	312.4	289.7	613.8	566.5
Net losses (gains) attributable to asset sales and insurance recoveries	(6.8)	5.7	(96.4)	(58.2)
Non-cash asset impairment charges	3.7	27.1	12.5	38.1
General and administrative costs	47.7	45.5	100.9	95.0
Total consolidated costs and expenses	$ 11,686.8	$ 10,412.7	$ 23,620.5	$ 20,882.6

(1) Represents cost of operating our plants, pipelines and other fixed assets, excluding depreciation, amortization and accretion charges.

Period-to-period fluctuations in our product sales revenues and related cost of sales amounts are explained in part by changes in energy commodity prices. In general, lower energy commodity prices result in a decrease in our revenues attributable to product sales; however, these lower commodity prices also decrease the associated cost of sales as purchase costs decline. The same correlation would be true in the case of higher energy commodity sales prices and purchase costs.

Note 12. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues – related parties:				
Unconsolidated affiliates	$ 17.3	$ 6.7	$ 52.8	$ 12.6
Costs and expenses – related parties:				
EPCO and affiliates	$ 239.5	$ 222.9	$ 475.2	$ 435.6
Unconsolidated affiliates	46.0	29.3	102.6	60.6
Total	$ 285.5	$ 252.2	$ 577.8	$ 496.2

The following table summarizes our related party accounts receivable and accounts payable balances at the dates indicated:

	June 30, 2014	December 31, 2013
Accounts receivable - related parties:		
Unconsolidated affiliates	$ 56.3	$ 6.8
Accounts payable - related parties:		
EPCO and affiliates	$ 101.9	$ 116.3
Unconsolidated affiliates	12.1	34.2
Total	$ 114.0	$ 150.5

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

Relationship with EPCO and Affiliates

We have an extensive and ongoing relationship with EPCO and its privately held affiliates (including Enterprise GP, our general partner), which are not a part of our consolidated group of companies. At June 30, 2014, EPCO and its privately held affiliates (including Dan Duncan LLC and certain Duncan family trusts, the beneficiaries of which include the estate of Dan L. Duncan) beneficially owned the following limited partner interests in us:

Number of Units	Percentage of Total Units Outstanding
341,641,866	36.4%

We and Enterprise GP are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are also separate from those of EPCO and its other affiliates. EPCO and its privately held affiliates depend on the cash distributions they receive from us and other investments to fund their other activities and to meet their debt obligations. During the six months ended June 30, 2014 and 2013, we paid EPCO and its privately held affiliates cash distributions totaling $431.8 million and $397.5 million, respectively.

From time-to-time, EPCO and its privately held affiliates elect to reinvest a portion of the cash distributions they receive from us into the purchase of additional common units under our DRIP. See Note 10 for information regarding reinvestments made during 2014.

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA or by other service providers.

The following table presents our costs and expenses attributable to the ASA and other related party transactions with EPCO for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Operating costs and expenses	$ 208.9	$ 193.1	$ 412.6	$ 374.2
General and administrative expenses	30.6	29.8	62.6	61.4
Total costs and expenses	$ 239.5	$ 222.9	$ 475.2	$ 435.6

Note 13. Earnings Per Unit

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

	For the Three Months Ended June 30		For the Six Months Ended June 30,	
	2014	2013	2014	2013
BASIC EARNINGS PER UNIT				
Net income attributable to limited partners	$ 637.7	$ 552.5	$ 1,436.5	$ 1,306.0
Undistributed earnings allocated and cash payments on phantom unit awards (1)	(1.2)	--	(2.7)	--
Net income available to common unitholders	$ 636.5	$ 552.5	$ 1,433.8	$ 1,306.0
Basic weighted-average number of common units outstanding	915.5	889.1	914.8	885.4
Basic earnings per unit	$ 0.70	$ 0.62	$ 1.57	$ 1.48
DILUTED EARNINGS PER UNIT				
Net income attributable to limited partners	$ 637.7	$ 552.5	$ 1,436.5	$ 1,306.0
Diluted weighted-average number of units outstanding:				
Distribution-bearing common units	915.5	889.1	914.8	885.4
Designated Units	22.6	23.7	22.6	23.7
Class B units (2)	--	4.5	--	4.5
Phantom units (1)	1.7	--	1.2	--
Incremental option units	0.4	1.2	0.5	1.2
Total	940.2	918.5	939.1	914.8
Diluted earnings per unit	$ 0.68	$ 0.60	$ 1.53	$ 1.43

(1) Each phantom unit award includes a DER, which entitles the recipient to receive cash payments equal to the product of the number of phantom unit awards and the cash distribution per unit paid to Enterprise's common unitholders. Cash payments made in connection with DERs are nonforfeitable. As a result, the phantom units are considered participating securities for purposes of computing basic earnings per unit. Phantom unit awards were first issued in February 2014.
(2) The Class B units automatically converted into an equal number of distribution-bearing common units in August 2013.

See Note 18 for information regarding a two-for-one common unit split announced on July 15, 2014 and its pro forma effects on earnings per unit.

Note 14. Commitments and Contingencies

Litigation

As part of our normal business activities, we may be named as defendants in legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to fully indemnify us against losses arising from future legal proceedings. We will vigorously defend the partnership in litigation matters.

Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the possible need for accounting recognition and disclosure of these contingencies. We accrue an undiscounted liability for those contingencies where the loss is probable and the amount can be reasonably estimated. If a range of probable loss amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum amount in the range is accrued.

We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when the likelihood of loss is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material to our consolidated financial statements, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss. Based on a consideration of all relevant known facts and circumstances, we do not believe that the ultimate outcome of any currently pending litigation directed against us will have a material impact on our consolidated financial statements either individually at the claim level or in the aggregate.

At June 30, 2014 and December 31, 2013, our accruals for litigation contingencies were $2.3 million and $3.7 million, respectively, and were recorded in our Unaudited Condensed Consolidated Balance Sheets as a component of "Other current liabilities." Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves uncertainties. In the event the assumptions we use to evaluate these matters change in future periods or new information becomes available, we may be required to record additional accruals. In an effort to mitigate expenses associated with litigation, we may settle legal proceedings out of court.

ETP Matter. In connection with a proposed pipeline project, we and Energy Transfer Partners, L.P. ("ETP") signed a non-binding letter of intent in April 2011 that disclaimed any partnership or joint venture related to such project absent executed definitive documents and board approvals of the respective companies. Definitive agreements were never executed and board approval was never obtained for the potential pipeline project. In August 2011, the proposed pipeline project was cancelled due to a lack of customer support.

In September 2011, ETP filed suit against us and a third party in connection with the cancelled project alleging, among other things, that we and ETP had formed a "partnership." The case was tried in the District Court of Dallas County, Texas, 298th Judicial District. While we firmly believe, and argued during our defense, that no agreement was ever executed forming a legal joint venture or partnership between the parties, the jury found that the actions of the two companies, nevertheless, constituted a legal partnership. As a result, the jury found that ETP was wrongfully excluded from a subsequent pipeline project involving a third party, and awarded ETP $319.4 million in actual damages on March 4, 2014. On July 29, 2014, the court entered judgment against us in an aggregate amount of $535.8 million, which includes (i) $319.4 million as the amount of actual damages awarded by the jury, (ii) an additional $150.0 million in disgorgement for the alleged benefit we received due to a breach of fiduciary duties by us against ETP and (iii) prejudgment interest in the amount of $66.4 million. The court also awarded post-judgment interest on such aggregate amount, to accrue at a rate of 5% per annum, compounded annually.

We do not believe that the verdict or the judgment entered against us is supported by the evidence or the law and intend to vigorously oppose the judgment through the appeals process. As of June 30, 2014, we have not recorded a provision for this matter as management believes payment of damages in this case is not probable.

Contractual Obligations

Scheduled Maturities of Debt. With the exception of routine fluctuations in the balance of our revolving credit facility and commercial paper notes, the issuance of senior notes in February 2014 and the scheduled repayment of maturing debt obligations, there have been no significant changes in our consolidated debt obligations since those reported in our 2013 Form 10-K. See Note 9 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations. Consolidated lease and rental expense was $22.5 million and $23.3 million during the second quarters of 2014 and 2013, respectively. For the six months ended June 30, 2014 and 2013, consolidated lease and rental expense was $45.7 million and $45.3 million, respectively.

During the second quarter of 2014, we entered into a long-term lease in connection with our plans to construct an ethane export terminal on the Houston Ship Channel. In addition, we entered into long-term railcar leases in connection with our other operations. On a combined basis, these agreements increased our estimated long-term operating lease obligations by approximately $34 million over the next five years and $144 million overall. Apart from these new agreements, there have been no other material changes in our operating lease commitments since those reported in our 2013 Form 10-K.

Purchase Obligations. There have been no material changes in our consolidated purchase obligations since those reported in our 2013 Form 10-K.

Note 15. Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance may not fully cover every type of damage, interruption or other loss that might occur.

We elected to forego windstorm coverage for our Gulf of Mexico offshore assets during the 2014 Atlantic hurricane season, which extends from June 1 through November 30. The combination of increasingly high deductibles and proposed premiums resulted in such coverage being uneconomic to us. Although EPCO's coverage does not provide any windstorm coverage for our offshore assets during the annual policy period that began on June 1, 2014, producers affiliated with our Independence Hub and Marco Polo platforms will continue to provide certain levels of physical damage windstorm coverage for each of these key offshore assets.

West Storage Claims

In February 2011, we experienced an NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. We collected $95.0 million and $8.8 million of nonrefundable cash insurance proceeds attributable to this incident during the six months ended June 30, 2014 and 2013, respectively. The payments we received during the first quarter of 2014 represent the final installments on this property damage claim.

Operating income for the six months ended June 30, 2014 and 2013 includes $95.0 million and $8.8 million, respectively, of gains related to these insurance recoveries. To the extent that we received nonrefundable cash insurance proceeds related to this incident, we recorded gains equal to such proceeds as a reduction in operating costs and expenses.

Note 16. Supplemental Cash Flow Information

The following table presents the net effect of changes in our operating accounts for the periods indicated:

	For the Six Months Ended June 30, 2014	For the Six Months Ended June 30, 2013
Decrease (increase) in:		
Accounts receivable – trade	$ 80.3	$ (312.6)
Accounts receivable – related parties	(43.4)	(17.2)
Inventories	(235.0)	(255.1)
Prepaid and other current assets	(64.3)	(42.2)
Other assets	21.5	0.8
Increase (decrease) in:		
Accounts payable – trade	(32.5)	35.3
Accounts payable – related parties	(36.5)	15.0
Accrued product payables	(0.6)	195.7
Accrued interest	15.3	2.8
Other current liabilities	90.0	(16.5)
Other liabilities	6.6	(15.2)
Net effect of changes in operating accounts	$ (198.6)	$ (409.2)

We incurred liabilities for construction in progress that had not been paid at June 30, 2014 and December 31, 2013 of $264.2 million and $205.3 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Unaudited Condensed Statements of Consolidated Cash Flows.

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction activities and production well tie-ins. These cash receipts are presented as "Contributions in aid of construction costs" within the investing activities section of our Unaudited Condensed Statements of Consolidated Cash Flows.

The following table presents our cash proceeds from asset sales and insurance recoveries for the periods indicated:

	For the Six Months Ended June 30, 2014	For the Six Months Ended June 30, 2013
Sale of Stratton Ridge-to-Mont Belvieu segment of Seminole Pipeline (see Note 6)	$ --	$ 86.9
Sale of lubrication oil and specialty chemical distribution assets (see Note 6)	--	35.3
Sale of chemical trucking assets	--	29.5
Insurance recoveries attributable to West Storage claims (see Note 15)	95.0	8.8
Other cash proceeds	18.2	38.7
Total	$ 113.2	$ 199.2

The following table presents net gains (losses) attributable to asset sales and insurance recoveries for the periods indicated:

	For the Six Months Ended June 30, 2014	For the Six Months Ended June 30, 2013
Sale of Stratton Ridge-to-Mont Belvieu segment of Seminole Pipeline (see Note 6)	$ --	$ 52.5
Gains attributable to West Storage insurance recoveries (see Note 15)	95.0	8.8
Net gains (losses) attributable to other asset sales	1.4	(3.1)
Total	$ 96.4	$ 58.2

Note 17. Condensed Consolidating Financial Information

EPO conducts all of our business. Currently, we have no independent operations and no material assets outside those of EPO.

EPO has issued publicly traded debt securities. Enterprise Products Partners L.P., as the parent company of EPO, guarantees the debt obligations of EPO, with the exception of the remaining debt obligations of TEPPCO. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full and unconditional repayment of that obligation. EPO's consolidated subsidiaries have no significant restrictions on their ability to pay distributions or make loans to Enterprise Products Partners L.P. See Note 9 for additional information regarding our consolidated debt obligations.

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
June 30, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 241.9	$ 76.6	$ (19.8)	$ 298.7	$ --	$ --	$ 298.7
Accounts receivable – trade, net	1,301.6	4,096.5	(4.6)	5,393.5	--	--	5,393.5
Accounts receivable – related parties	272.9	1,369.6	(1,576.7)	65.8	--	(9.5)	56.3
Inventories	868.6	450.8	(1.1)	1,318.3	--	--	1,318.3
Prepaid and other current assets	183.0	232.1	(12.2)	402.9	0.3	1.9	405.1
Total current assets	2,868.0	6,225.6	(1,614.4)	7,479.2	0.3	(7.6)	7,471.9
Property, plant and equipment, net	2,174.9	25,378.3	1.5	27,554.7	--	--	27,554.7
Investments in unconsolidated affiliates	32,133.4	3,400.6	(32,654.7)	2,879.3	15,585.7	(15,585.7)	2,879.3
Intangible assets, net	81.1	1,349.2	(15.4)	1,414.9	--	--	1,414.9
Goodwill	458.8	1,621.1	--	2,079.9	--	--	2,079.9
Other assets	130.0	41.9	(1.4)	170.5	0.1	--	170.6
Total assets	$ 37,846.2	$ 38,016.7	$ (34,284.4)	$ 41,578.5	$ 15,586.1	$ (15,593.3)	$ 41,571.3
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 1,300.0	$ --	$ --	$ 1,300.0	$ --	$ --	$ 1,300.0
Accounts payable – trade	257.0	468.7	(19.8)	705.9	--	--	705.9
Accounts payable – related parties	1,527.0	178.2	(1,591.2)	114.0	9.5	(9.5)	114.0
Accrued product payables	1,726.4	3,886.5	(6.3)	5,606.6	--	--	5,606.6
Accrued interest	319.5	0.1	--	319.6	--	--	319.6
Other current liabilities	73.5	363.1	(12.8)	423.8	--	--	423.8
Total current liabilities	5,203.4	4,896.6	(1,630.1)	8,469.9	9.5	(9.5)	8,469.9
Long-term debt	17,048.0	14.9	--	17,062.9	--	--	17,062.9
Deferred tax liabilities	4.0	54.7	(1.4)	57.3	--	3.9	61.2
Other long-term liabilities	10.0	165.4	(0.5)	174.9	--	--	174.9
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	15,580.8	32,815.3	(32,834.9)	15,561.2	15,576.6	(15,561.2)	15,576.6
Noncontrolling interests	--	69.8	182.5	252.3	--	(26.5)	225.8
Total equity	15,580.8	32,885.1	(32,652.4)	15,813.5	15,576.6	(15,587.7)	15,802.4
Total liabilities and equity	$ 37,846.2	$ 38,016.7	$ (34,284.4)	$ 41,578.5	$ 15,586.1	$ (15,593.3)	$ 41,571.3

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
December 31, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 93.9	$ 49.5	$ (20.9)	$ 122.5	$ --	$ --	$ 122.5
Accounts receivable – trade, net	1,986.8	3,491.1	(2.4)	5,475.5	--	--	5,475.5
Accounts receivable – related parties	384.7	1,348.1	(1,726.0)	6.8	0.2	(0.2)	6.8
Inventories	948.5	145.4	(0.8)	1,093.1	--	--	1,093.1
Prepaid and other current assets	140.9	191.4	(6.8)	325.5	--	--	325.5
Total current assets	3,554.8	5,225.5	(1,756.9)	7,023.4	0.2	(0.2)	7,023.4
Property, plant and equipment, net	1,945.0	24,999.7	1.9	26,946.6	--	--	26,946.6
Investments in unconsolidated affiliates	30,819.9	2,921.2	(31,304.0)	2,437.1	15,214.5	(15,214.5)	2,437.1
Intangible assets, net	76.9	1,385.3	--	1,462.2	--	--	1,462.2
Goodwill	458.9	1,621.1	--	2,080.0	--	--	2,080.0
Other assets	123.5	67.2	(1.4)	189.3	0.1	--	189.4
Total assets	$ 36,979.0	$ 36,220.0	$ (33,060.4)	$ 40,138.6	$ 15,214.8	$ (15,214.7)	$ 40,138.7
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 1,125.0	$ --	$ --	$ 1,125.0	$ --	$ --	$ 1,125.0
Accounts payable – trade	103.0	641.6	(20.9)	723.7	--	--	723.7
Accounts payable – related parties	1,541.8	333.8	(1,724.9)	150.7	--	(0.2)	150.5
Accrued product payables	2,388.6	3,224.5	(4.4)	5,608.7	--	--	5,608.7
Accrued interest	304.2	0.1	--	304.3	--	--	304.3
Other current liabilities	92.3	242.4	(6.7)	328.0	--	(1.5)	326.5
Total current liabilities	5,554.9	4,442.4	(1,756.9)	8,240.4	--	(1.7)	8,238.7
Long-term debt	16,211.6	14.9	--	16,226.5	--	--	16,226.5
Deferred tax liabilities	4.3	55.0	(1.4)	57.9	--	2.9	60.8
Other long-term liabilities	11.8	160.5	--	172.3	--	--	172.3
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	15,196.4	31,475.9	(31,482.4)	15,189.9	15,214.8	(15,189.9)	15,214.8
Noncontrolling interests	--	71.3	180.3	251.6	--	(26.0)	225.6
Total equity	15,196.4	31,547.2	(31,302.1)	15,441.5	15,214.8	(15,215.9)	15,440.4
Total liabilities and equity	$ 36,979.0	$ 36,220.0	$ (33,060.4)	$ 40,138.6	$ 15,214.8	$ (15,214.7)	$ 40,138.7

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Three Months Ended June 30, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 7,577.7	$ 9,151.1	$ (4,208.0)	$ 12,520.8	$ --	$ --	$ 12,520.8
Costs and expenses:							
Operating costs and expenses	7,397.9	8,449.6	(4,208.4)	11,639.1	--	--	11,639.1
General and administrative costs	7.6	39.9	--	47.5	0.2	--	47.7
Total costs and expenses	7,405.5	8,489.5	(4,208.4)	11,686.6	0.2	--	11,686.8
Equity in income of unconsolidated affiliates	700.2	75.9	(725.8)	50.3	637.9	(637.9)	50.3
Operating income	872.4	737.5	(725.4)	884.5	637.7	(637.9)	884.3
Other income (expense):							
Interest expense	(228.6)	(0.3)	--	(228.9)	--	--	(228.9)
Other, net	0.3	0.8	--	1.1	--	--	1.1
Total other expense, net	(228.3)	0.5	--	(227.8)	--	--	(227.8)
Income before income taxes	644.1	738.0	(725.4)	656.7	637.7	(637.9)	656.5
Provision for income taxes	(7.3)	(2.7)	0.2	(9.8)	--	(0.2)	(10.0)
Net income	636.8	735.3	(725.2)	646.9	637.7	(638.1)	646.5
Net loss (income) attributable to noncontrolling interests	--	0.1	(10.2)	(10.1)	--	1.3	(8.8)
Net income attributable to entity	$ 636.8	$ 735.4	$ (735.4)	$ 636.8	$ 637.7	$ (636.8)	$ 637.7

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Three Months Ended June 30, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 6,491.0	$ 8,015.7	$ (3,357.4)	$ 11,149.3	$ --	$ --	$ 11,149.3
Costs and expenses:							
Operating costs and expenses	6,326.6	7,398.1	(3,357.5)	10,367.2	--	--	10,367.2
General and administrative costs	7.4	37.4	--	44.8	0.7	--	45.5
Total costs and expenses	6,334.0	7,435.5	(3,357.5)	10,412.0	0.7	--	10,412.7
Equity in income of unconsolidated affiliates	612.3	42.9	(617.6)	37.6	553.2	(553.2)	37.6
Operating income	769.3	623.1	(617.5)	774.9	552.5	(553.2)	774.2
Other income (expense):							
Interest expense	(199.7)	(0.5)	--	(200.2)	--	--	(200.2)
Other, net	0.1	(0.4)	--	(0.3)	--	--	(0.3)
Total other expense, net	(199.6)	(0.9)	--	(200.5)	--	--	(200.5)
Income before income taxes	569.7	622.2	(617.5)	574.4	552.5	(553.2)	573.7
Provision for income taxes	(17.5)	(2.9)	--	(20.4)	--	--	(20.4)
Net income	552.2	619.3	(617.5)	554.0	552.5	(553.2)	553.3
Net income attributable to noncontrolling interests	--	(0.4)	(1.3)	(1.7)	--	0.9	(0.8)
Net income attributable to entity	$ 552.2	$ 618.9	$ (618.8)	$ 552.3	$ 552.5	$ (552.3)	$ 552.5

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Six Months Ended June 30, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 17,068.6	$ 17,261.7	$ (8,899.6)	$ 25,430.7	$ --	$ --	$ 25,430.7
Costs and expenses:							
Operating costs and expenses	16,565.7	15,854.1	(8,900.2)	23,519.6	--	--	23,519.6
General and administrative costs	14.9	85.6	--	100.5	0.4	--	100.9
Total costs and expenses	16,580.6	15,939.7	(8,900.2)	23,620.1	0.4	--	23,620.5
Equity in income of unconsolidated affiliates	1,407.0	161.7	(1,461.9)	106.8	1,436.9	(1,436.9)	106.8
Operating income	1,895.0	1,483.7	(1,461.3)	1,917.4	1,436.5	(1,436.9)	1,917.0
Other income (expense):							
Interest expense	(449.4)	(0.4)	--	(449.8)	--	--	(449.8)
Other, net	0.5	0.3	--	0.8	--	--	0.8
Total other expense, net	(448.9)	(0.1)	--	(449.0)	--	--	(449.0)
Income before income taxes	1,446.1	1,483.6	(1,461.3)	1,468.4	1,436.5	(1,436.9)	1,468.0
Provision for income taxes	(11.5)	(3.0)	0.2	(14.3)	--	(0.5)	(14.8)
Net income	1,434.6	1,480.6	(1,461.1)	1,454.1	1,436.5	(1,437.4)	1,453.2
Net loss (income) attributable to noncontrolling interests	--	0.1	(19.3)	(19.2)	--	2.5	(16.7)
Net income attributable to entity	$ 1,434.6	$ 1,480.7	$ (1,480.4)	$ 1,434.9	$ 1,436.5	$ (1,434.9)	$ 1,436.5

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Six Months Ended June 30, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 13,846.5	$ 15,456.1	$ (6,770.2)	$ 22,532.4	$ --	$ --	$ 22,532.4
Costs and expenses:							
Operating costs and expenses	13,470.5	14,087.3	(6,770.2)	20,787.6	--	--	20,787.6
General and administrative costs	12.1	82.0	--	94.1	0.9	--	95.0
Total costs and expenses	13,482.6	14,169.3	(6,770.2)	20,881.7	0.9	--	20,882.6
Equity in income of unconsolidated affiliates	1,359.0	94.1	(1,371.0)	82.1	1,306.9	(1,306.9)	82.1
Operating income	1,722.9	1,380.9	(1,371.0)	1,732.8	1,306.0	(1,306.9)	1,731.9
Other income (expense):							
Interest expense	(395.0)	(1.1)	--	(396.1)	--	--	(396.1)
Other, net	0.2	(0.6)	--	(0.4)	--	--	(0.4)
Total other expense, net	(394.8)	(1.7)	--	(396.5)	--	--	(396.5)
Income before income taxes	1,328.1	1,379.2	(1,371.0)	1,336.3	1,306.0	(1,306.9)	1,335.4
Provision for income taxes	(22.6)	(3.9)	--	(26.5)	--	(0.3)	(26.8)
Net income	1,305.5	1,375.3	(1,371.0)	1,309.8	1,306.0	(1,307.2)	1,308.6
Net income attributable to noncontrolling interests	--	(0.9)	(3.3)	(4.2)	--	1.6	(2.6)
Net income attributable to entity	$ 1,305.5	$ 1,374.4	$ (1,374.3)	$ 1,305.6	$ 1,306.0	$ (1,305.6)	$ 1,306.0

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Three Months Ended June 30, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 644.9	$ 717.2	$ (725.1)	$ 637.0	$ 627.8	$ (628.2)	$ 636.6
Comprehensive loss (income) attributable to noncontrolling interests	--	0.1	(10.2)	(10.1)	--	1.3	(8.8)
Comprehensive income attributable to entity	$ 644.9	$ 717.3	$ (735.3)	$ 626.9	$ 627.8	$ (626.9)	$ 627.8

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Three Months Ended June 30, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 575.1	$ 631.6	$ (617.6)	$ 589.1	$ 587.6	$ (588.3)	$ 588.4
Comprehensive income attributable to noncontrolling interests	--	(0.4)	(1.3)	(1.7)	--	0.9	(0.8)
Comprehensive income attributable to entity	$ 575.1	$ 631.2	$ (618.9)	$ 587.4	$ 587.6	$ (587.4)	$ 587.6

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Six Months Ended June 30, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 1,452.9	$ 1,467.0	$ (1,461.0)	$ 1,458.9	$ 1,441.3	$ (1,442.2)	$ 1,458.0
Comprehensive loss (income) attributable to noncontrolling interests	--	0.1	(19.3)	(19.2)	--	2.5	(16.7)
Comprehensive income attributable to entity	$ 1,452.9	$ 1,467.1	$ (1,480.3)	$ 1,439.7	$ 1,441.3	$ (1,439.7)	$ 1,441.3

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Six Months Ended June 30, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 1,328.1	$ 1,360.0	$ (1,371.0)	$ 1,317.1	$ 1,313.4	$ (1,314.5)	$ 1,316.0
Comprehensive income attributable to noncontrolling interests	--	(0.9)	(3.3)	(4.2)	--	1.6	(2.6)
Comprehensive income attributable to entity	$ 1,328.1	$ 1,359.1	$ (1,374.3)	$ 1,312.9	$ 1,313.4	$ (1,312.9)	$ 1,313.4

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
For the Six Months Ended June 30, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 1,434.6	$ 1,480.6	$ (1,461.1)	$ 1,454.1	$ 1,436.5	$ (1,437.4)	$ 1,453.2
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	74.9	576.3	(0.2)	651.0	--	--	651.0
Equity in income of unconsolidated affiliates	(1,407.0)	(161.7)	1,461.9	(106.8)	(1,436.9)	1,436.9	(106.8)
Distributions received from unconsolidated affiliates	1,829.3	137.9	(1,810.1)	157.1	1,346.5	(1,346.5)	157.1
Net effect of changes in operating accounts and other operating activities	(334.9)	56.5	0.6	(277.8)	(5.3)	0.5	(282.6)
Net cash flows provided by operating activities	1,596.9	2,089.6	(1,808.9)	1,877.6	1,340.8	(1,346.5)	1,871.9
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(166.8)	(1,005.7)	--	(1,172.5)	--	--	(1,172.5)
Proceeds from asset sales and insurance recoveries	3.8	109.4	--	113.2	--	--	113.2
Other investing activities	(1,155.2)	(443.7)	1,103.3	(495.6)	(221.3)	221.3	(495.6)
Cash used in investing activities	(1,318.2)	(1,340.0)	1,103.3	(1,554.9)	(221.3)	221.3	(1,554.9)
Financing activities:							
Borrowings under debt agreements	4,182.8	--	--	4,182.8	--	--	4,182.8
Repayments of debt	(3,161.3)	--	--	(3,161.3)	--	--	(3,161.3)
Cash distributions paid to partners	(1,346.5)	(1,829.8)	1,829.8	(1,346.5)	(1,288.4)	1,346.5	(1,288.4)
Cash payments made in connection with DERs	--	--	--	--	(1.2)	--	(1.2)
Cash distributions paid to noncontrolling interests	--	--	(19.7)	(19.7)	--	--	(19.7)
Cash contributions from noncontrolling interests	--	--	4.0	4.0	--	--	4.0
Net cash proceeds from issuance of common units	--	--	--	--	223.3	--	223.3
Cash contributions from owners	221.3	1,107.3	(1,107.3)	221.3	--	(221.3)	--
Other financing activities	(18.2)	--	--	(18.2)	(53.2)	--	(71.4)
Cash used in financing activities	(121.9)	(722.5)	706.8	(137.6)	(1,119.5)	1,125.2	(131.9)
Net change in cash and cash equivalents	156.8	27.1	1.2	185.1	--	--	185.1
Cash and cash equivalents, January 1	28.4	49.5	(21.0)	56.9	--	--	56.9
Cash and cash equivalents, June 30	$ 185.2	$ 76.6	$ (19.8)	$ 242.0	$ --	$ --	$ 242.0

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
For the Six Months Ended June 30, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 1,305.5	$ 1,375.3	$ (1,371.0)	$ 1,309.8	$ 1,306.0	$ (1,307.2)	$ 1,308.6
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	69.8	530.0	--	599.8	--	--	599.8
Equity in income of unconsolidated affiliates	(1,359.0)	(94.1)	1,371.0	(82.1)	(1,306.9)	1,306.9	(82.1)
Distributions received from unconsolidated affiliates	2,432.2	116.8	(2,429.7)	119.3	1,195.6	(1,195.6)	119.3
Net effect of changes in operating accounts and other operating activities	(744.5)	337.1	1.5	(405.9)	21.6	(30.4)	(414.7)
Net cash flows provided by operating activities	1,704.0	2,265.1	(2,428.2)	1,540.9	1,216.3	(1,226.3)	1,530.9
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(129.3)	(1,303.1)	--	(1,432.4)	--	--	(1,432.4)
Proceeds from asset sales and insurance recoveries	12.6	186.6	--	199.2	--	--	199.2
Other investing activities	(1,798.7)	(361.1)	1,590.4	(569.4)	(835.8)	835.8	(569.4)
Cash used in investing activities	(1,915.4)	(1,477.6)	1,590.4	(1,802.6)	(835.8)	835.8	(1,802.6)
Financing activities:							
Borrowings under debt agreements	7,064.5	--	--	7,064.5	--	--	7,064.5
Repayments of debt	(6,251.7)	(29.9)	--	(6,281.6)	--	--	(6,281.6)
Cash distributions paid to partners	(1,226.3)	(2,434.4)	2,434.4	(1,226.3)	(1,171.9)	1,226.3	(1,171.9)
Cash distributions paid to noncontrolling interests	--	--	(4.7)	(4.7)	--	--	(4.7)
Cash contributions from noncontrolling interests	--	--	95.9	95.9	--	--	95.9
Net cash proceeds from issuance of common units	--	--	--	--	835.4	--	835.4
Cash contributions from owners	835.8	1,686.2	(1,686.2)	835.8	--	(835.8)	--
Other financing activities	(192.6)	0.1	--	(192.5)	(44.2)	--	(236.7)
Cash provided by (used in) financing activities	229.7	(778.0)	839.4	291.1	(380.7)	390.5	300.9
Net change in cash and cash equivalents	18.3	9.5	1.6	29.4	(0.2)	--	29.2
Cash and cash equivalents, January 1	--	28.0	(12.1)	15.9	0.2	--	16.1
Cash and cash equivalents, June 30	$ 18.3	$ 37.5	$ (10.5)	$ 45.3	$ --	$ --	$ 45.3

Note 18. Subsequent Event

Two-for-One Split of Limited Partner Units

On July 15, 2014, we announced that our general partner approved a two-for-one split of our common units. The common unit split will be accomplished by distributing one additional common unit for each common unit outstanding. The additional common units will be distributed on August 21, 2014 to holders of record as of the close of business on August 14, 2014.

All per unit amounts and number of units outstanding in these Unaudited Condensed Consolidated Financial Statements and Notes thereto are presented on a pre-split basis. As a result of the common unit split, all historical per unit data and number of units outstanding presented in future financial statements will be retroactively adjusted.

The following table presents pro forma earnings per unit (giving retroactive effect solely to the unit split) for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Net income available to common unitholders (see Note 13)	$ 636.5	$ 552.5	$ 1,433.8	$ 1,306.0
Basic earnings per unit:				
Weighted-average number of common units outstanding, as reported	915.5	889.1	914.8	885.4
Weighted-average number of common units outstanding, pro forma	1,831.0	1,778.2	1,829.6	1,770.8
Basic earnings per unit, as reported	$ 0.70	$ 0.62	$ 1.57	$ 1.48
Basic earnings per unit, pro forma	$ 0.35	$ 0.31	$ 0.78	$ 0.74
Diluted earnings per unit:				
Weighted-average number of common units outstanding, as reported	940.2	918.5	939.1	914.8
Weighted-average number of common units outstanding, pro forma	1,880.4	1,837.0	1,878.2	1,829.6
Diluted earnings per unit, as reported	$ 0.68	$ 0.60	$ 1.53	$ 1.43
Diluted earnings per unit, pro forma	$ 0.34	$ 0.30	$ 0.76	$ 0.71

Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations.***

For the Three and Six Months Ended June 30, 2014 and 2013.

The following information should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and accompanying Notes included in this quarterly report on Form 10-Q and the Audited Consolidated Financial Statements and related Notes, together with our discussion and analysis of financial position and results of operations, included in our annual report on Form 10-K for the year ended December 31, 2013, as filed on March 3, 2014 (the "2013 Form 10-K"). Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States ("U.S.").

Unless the context requires otherwise, references to "we," "us," "our," "Enterprise" or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise, and its consolidated subsidiaries, through which Enterprise Products Partners L.P. conducts its business. Enterprise is managed by its general partner, Enterprise Products Holdings LLC ("Enterprise GP"), which is a wholly owned subsidiary of Dan Duncan LLC, a privately held Texas limited liability company.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director and Chairman of the Board of Enterprise GP; (ii) Dr. Ralph S. Cunningham; and (iii) Richard H. Bachmann. Each of the DD LLC Trustees also currently serves as one of the three managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company, a privately held Texas corporation, and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Williams, who also serves as Chairman of EPCO; (ii) Dr. Cunningham, who also serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who also serves as the President and Chief Executive Officer ("CEO") of EPCO. Each of the EPCO Trustees is also a director of EPCO.

In addition to owning our general partner, privately held affiliates of EPCO owned approximately 36.4% of our limited partner interests at June 30, 2014.

As generally used in the energy industry and in this quarterly report, the acronyms below have the following meanings:

/d	*= per day*	*MMBbls*	*= million barrels*
BBtus	*= billion British thermal units*	*MMBPD*	*= million barrels per day*
Bcf	*= billion cubic feet*	*MMBtus*	*= million British thermal units*
BPD	*= barrels per day*	*MMcf*	*= million cubic feet*
MBPD	*= thousand barrels per day*	*TBtus*	*= trillion British thermal units*

Cautionary Statement Regarding Forward-Looking Information

This quarterly report on Form 10-Q contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "would," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that our expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under "Risk Factors" within Part I, Item 1A included in our 2013 Form 10-K. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put *undue reliance on any forward-looking statements. The forward-looking statements in this quarterly report speak only as of the filing date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.*

Overview of Business

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products.

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals (including liquefied petroleum gas or "LPG"); crude oil gathering, transportation, storage and terminals; offshore production platforms; petrochemical and refined products transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our assets include approximately 51,000 miles of onshore and offshore pipelines; 200 MMBbls of storage capacity for NGLs, petrochemicals, refined products and crude oil; and 14 Bcf of natural gas storage capacity. In addition, our asset portfolio includes 24 natural gas processing plants, 22 NGL and propylene fractionators, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and LPG export terminals, and octane enhancement and high-purity isobutylene production facilities.

We conduct substantially all of our business through EPO and are owned 100% by our limited partners from an economic perspective. Enterprise GP manages our partnership and owns a non-economic general partner interest in us. Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement or by other service providers.

We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. For information regarding our business segments, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Significant Recent Developments

The following information highlights significant commercial and operational developments since January 1, 2014 through the date of this filing (August 11, 2014). For information regarding recent offerings of our equity and debt securities, see "Liquidity and Capital Resources" within this Part I, Item 2.

SEKCO Oil Pipeline Completed

In July 2014, we announced that the SEKCO Oil Pipeline was mechanically complete and began earning revenues July 1, 2014. The SEKCO Oil Pipeline is owned by Southeast Keathley Canyon Pipeline Company, L.L.C., which is 50/50 owned by us and Genesis Energy, L.P.

The SEKCO Oil Pipeline is a 149-mile crude oil gathering pipeline serving producers in the Lucius oil and gas field located in the southern Keathley Canyon area of the deepwater central Gulf of Mexico. The new pipeline connects the third party-owned Lucius-truss spar floating production platform to an existing junction platform at

South Marsh Island 205, which is part of our Poseidon Oil Pipeline System. We serve as operator of the SEKCO Oil Pipeline, which has a capacity of 115 MPBD.

Seaway Crude Oil Pipeline Loop Completed

In June 2014, Seaway Crude Pipeline Company LLC ("Seaway") completed a pipeline looping project involving its Longhaul System. This expansion project entailed the construction of an additional 512-mile, 30-inch pipeline that will transport crude oil southbound from the Cushing hub to Seaway's Jones Creek terminal. With the looping project complete, the aggregate transportation capacity of the Longhaul System is expected to be up to approximately 850 MBPD, depending on the type and mix of crude oil being transported and other variables.

Seaway's Jones Creek terminal is connected to our Enterprise Crude Houston ("ECHO") crude oil storage facility located in Houston, Texas by a 65-mile, 36-inch pipeline. Construction of a 100-mile, 30-inch pipeline from ECHO to Beaumont/Port Arthur, Texas, was also completed in July 2014. These new pipeline construction projects complement ongoing expansion activities at ECHO, which include the completion of three new storage tanks during the second quarter of 2014. Commissioning of the looping project, as well as the new pipeline from ECHO to Beaumont/Port Arthur will continue throughout the third quarter of 2014.

Marine Terminal Begins Exporting Refined Products

In May 2014, we began loading cargoes of refined products for export on our reactivated marine terminal in Beaumont, Texas. Located on the Neches River, the terminal can load at rates up to 15,000 barrels per hour. The facility includes a dock that can accommodate Panamax size vessels with a 40-foot draft and have a capacity of up to 400,000 barrels. The terminal has access to more than 12.0 MMBbls of refined products storage and receives products from eight refineries, representing approximately 3.3 MMBPD of capacity, as well as the Colonial Pipeline.

The costs for improvements and modifications required to resume operations at the terminal, which included channel dredging, new pipeline construction, and the installation of new loading arms and vapor recovery systems, are supported by shipper commitments. Future plans for the Beaumont refined products terminal include the addition of a second dock and significant on-site storage for blending components. With its strategic location and enhanced capabilities, the Beaumont marine terminal provides optionality for customers, allowing them to capture added value from the evolving fundamentals of the domestic and international refined products markets.

Plans to Construct Ethane Export Facility on Houston Ship Channel

In April 2014, we announced plans to construct a fully refrigerated ethane export facility on the U.S. Gulf Coast. The new facility, which is located on the Houston Ship Channel, is expected to have an aggregate loading rate of approximately 10,000 barrels per hour and is supported by long-term contracts. We expect the ethane export facility to begin operations in the third quarter of 2016.

Our ethane export facility will provide new markets for domestically-produced ethane, and will assist U.S. producers in increasing their associated production of natural gas and crude oil. We estimate that U.S. ethane production capacity currently exceeds U.S. demand by 300 MBPD and could exceed demand by up to 700 MBPD by 2020, after considering the estimated incremental demand from new ethylene facilities that have been announced.

The ethane export facility will be integrated with our Mont Belvieu complex, which includes over 650 MBPD of NGL fractionation capacity and approximately 110 MMBbls of NGL storage capacity. Our Mont Belvieu complex receives NGL supplies from several major producing basins across the U.S., including the Marcellus and Utica Shales via our recently completed Appalachia-to-Texas Express ("ATEX") ethane pipeline. We believe that our integrated NGL system offers supply assurance and diversification for the ethane export facility.

Front Range Pipeline Begins Operations

Our Front Range Pipeline commenced operations in February 2014. This 435-mile pipeline transports NGLs originating from the Denver-Julesburg production basin in Weld County, Colorado to Skellytown, Texas in Carson County. With connections to our Mid-America Pipeline System and Texas Express Pipeline, the Front Range Pipeline provides producers in the Denver-Julesburg basin with access to the Gulf Coast, which is the largest NGL market in the U.S. Initial throughput capacity for the Front Range Pipeline is 150 MBPD, which could be expanded to approximately 230 MBPD with certain system modifications. The Front Range Pipeline is owned by Front Range Pipeline LLC, which is a joint venture among us and affiliates of DCP Midstream Partners LP and Anadarko Petroleum Corporation. We operate the Front Range Pipeline and own a one-third member interest in Front Range Pipeline LLC.

ATEX Pipeline Begins Operations

Our ATEX pipeline, which commenced operations in January 2014, transports ethane primarily southbound from NGL fractionation plants located in Pennsylvania, West Virginia and Ohio to our Mont Belvieu storage complex. The ethane extracted by these fractionation facilities originates from the Marcellus and Utica Shale production areas. In addition to newly constructed pipeline segments, significant portions of the ATEX pipeline consist of segments that were formerly used in refined products transportation service by our TE Products Pipeline. Initial throughput capacity for the ATEX pipeline is 125 MBPD, which could be expanded to approximately 265 MBPD with certain system modifications.

ATEX terminates at our Mont Belvieu storage facility, which includes approximately 110 MMBbls of NGL and petroleum liquid storage capacity and an extensive pipeline distribution system. With the addition of our Aegis Ethane Pipeline ("Aegis," currently under construction with full operations expected by the end of 2015), we will link Marcellus and Utica Shale-produced ethane to existing ethylene production facilities along the U.S. Gulf Coast and provide supply security to support construction of new third-party ethylene plants currently planned in Texas and Louisiana. Also, ethane volumes delivered to Mont Belvieu via ATEX may support our recently announced ethane export facility.

Expansion of Houston Ship Channel LPG Export Terminal

We provide customers with LPG export services at our marine terminal located on the Houston Ship Channel. This terminal has the capability to load cargoes of fully refrigerated, low-ethane propane and/or butane onto multiple tanker vessels simultaneously. In March 2013, we completed an expansion project at this terminal that increased its loading capability from 4.0 MMBbls per month to 7.5 MMBbls per month. Our LPG export services continue to benefit from increased NGL supplies produced from domestic shale plays such as the Eagle Ford Shale and strong international demand for propane as a feedstock in ethylene plant operations and for power generation and heating purposes.

In September 2013, we announced an expansion project at this LPG export terminal that is expected to increase its ability to load cargoes from 7.5 MMBbls per month to approximately 9.0 MMBbls per month. This expansion project is expected to be completed in the first quarter of 2015.

In January 2014, we announced a further expansion of this LPG export terminal that is expected to increase its ability to load cargoes from approximately 9.0 MMBbls per month to in excess of 16.0 MMBbls per month. Once this expansion project is completed, we expect our maximum loading capacity at this export terminal will be approximately 27,000 barrels per hour. This expansion project is supported by a 50-year service agreement with Oiltanking Partners, L.P., which has agreed to provide additional dock space and related services to us at the terminal site. The expanded LPG export terminal is expected to be in service by the end of 2015 and is supported by long-term LPG export agreements.

Mid-America Pipeline System's Rocky Mountain Expansion Project Begins Operations

In January 2014, we announced the completion of an expansion project involving the Rocky Mountain pipeline of our Mid-America Pipeline System. This expansion project involved looping 265 miles of the Rocky

Mountain pipeline, as well as related pump station modifications, which increased transportation capacity on the pipeline from approximately 275 MBPD to 350 MBPD (after taking into account shipper commitments to the expansion project). This expansion project was built to accommodate growing natural gas and NGL production from major supply basins in Colorado, New Mexico, Utah and Wyoming.

Results of Operations

Summarized Consolidated Income Statement Data

The following table summarizes the key components of our results of operations for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues	$ 12,520.8	$ 11,149.3	$ 25,430.7	$ 22,532.4
Costs and expenses:				
Operating costs and expenses:				
Cost of sales	10,705.3	9,458.3	21,758.0	19,150.8
Other operating costs and expenses	624.5	586.4	1,231.7	1,090.4
Depreciation, amortization and accretion expenses	312.4	289.7	613.8	566.5
Net losses (gains) attributable to asset sales and insurance recoveries	(6.8)	5.7	(96.4)	(58.2)
Non-cash asset impairment charges	3.7	27.1	12.5	38.1
Total operating costs and expenses	11,639.1	10,367.2	23,519.6	20,787.6
General and administrative costs	47.7	45.5	100.9	95.0
Total costs and expenses	11,686.8	10,412.7	23,620.5	20,882.6
Equity in income of unconsolidated affiliates	50.3	37.6	106.8	82.1
Operating income	884.3	774.2	1,917.0	1,731.9
Interest expense	(228.9)	(200.2)	(449.8)	(396.1)
Other, net	1.1	(0.3)	0.8	(0.4)
Provision for income taxes	(10.0)	(20.4)	(14.8)	(26.8)
Net income	646.5	553.3	1,453.2	1,308.6
Net income attributable to noncontrolling interests	(8.8)	(0.8)	(16.7)	(2.6)
Net income attributable to limited partners	$ 637.7	$ 552.5	$ 1,436.5	$ 1,306.0

The following table presents each business segment's contribution to revenues (net of eliminations) for the periods indicated (dollars in millions):

	For the Three Months Ended June 30, 2014	For the Three Months Ended June 30, 2013	For the Six Months Ended June 30, 2014	For the Six Months Ended June 30, 2013
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 3,630.6	$ 3,235.9	$ 8,426.4	$ 6,901.5
Midstream services	390.6	269.0	774.3	554.4
Total	4,021.2	3,504.9	9,200.7	7,455.9
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	787.0	723.9	1,740.2	1,363.4
Midstream services	254.0	233.6	505.4	471.8
Total	1,041.0	957.5	2,245.6	1,835.2
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	5,781.9	5,057.4	10,655.3	9,800.2
Midstream services	90.4	72.1	175.3	122.5
Total	5,872.3	5,129.5	10,830.6	9,922.7
Offshore Pipelines & Services:				
Sales of natural gas	--	0.1	0.2	0.2
Sales of crude oil	2.9	(0.1)	5.0	2.2
Midstream services	36.1	41.3	70.7	81.5
Total	39.0	41.3	75.9	83.9
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,376.6	1,334.2	2,732.8	2,881.4
Midstream services	170.7	181.9	345.1	353.3
Total	1,547.3	1,516.1	3,077.9	3,234.7
Total consolidated revenues	$ 12,520.8	$ 11,149.3	$ 25,430.7	$ 22,532.4

Selected Energy Commodity Price Data

The following table presents index prices for natural gas, crude oil and selected NGL and petrochemical products for the periods indicated:

	Natural Gas, $/MMBtu	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound	WTI Crude Oil, $/barrel	LLS Crude Oil, $/barrel
	(1)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(4)	(4)
2013 by quarter:										
1st Quarter	$ 3.34	$ 0.26	$ 0.86	$ 1.58	$ 1.65	$ 2.23	$ 0.75	$ 0.65	$ 94.37	$ 113.93
2nd Quarter	$ 4.10	$ 0.27	$ 0.91	$ 1.24	$ 1.27	$ 2.04	$ 0.63	$ 0.53	$ 94.22	$ 104.63
3rd Quarter	$ 3.58	$ 0.25	$ 1.03	$ 1.33	$ 1.35	$ 2.15	$ 0.68	$ 0.58	$ 105.82	$ 109.89
4th Quarter	$ 3.60	$ 0.26	$ 1.20	$ 1.43	$ 1.45	$ 2.10	$ 0.68	$ 0.56	$ 97.46	$ 100.94
2013 Averages	$ 3.65	$ 0.26	$ 1.00	$ 1.39	$ 1.43	$ 2.13	$ 0.69	$ 0.58	$ 97.97	$ 107.34
2014 by quarter:										
1st Quarter	$ 4.95	$ 0.34	$ 1.30	$ 1.39	$ 1.42	$ 2.12	$ 0.73	$ 0.61	$ 98.68	$ 104.43
2nd Quarter	$ 4.68	$ 0.29	$ 1.06	$ 1.25	$ 1.30	$ 2.21	$ 0.70	$ 0.57	$ 102.99	$ 105.55
2014 Averages	$ 4.81	$ 0.31	$ 1.18	$ 1.32	$ 1.36	$ 2.17	$ 0.72	$ 0.59	$ 100.84	$ 104.99

(1) Natural gas prices are based on Henry-Hub Inside FERC commercial index prices as reported by Platts, which is a division of The McGraw-Hill Companies.
(2) NGL prices for ethane, propane, normal butane, isobutane and natural gasoline are based on Mont Belvieu Non-TET commercial index prices as reported by Oil Price Information Service.
(3) Polymer-grade propylene prices represent average contract pricing for such product as reported by Chemical Market Associates, Inc. ("CMAI"). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by CMAI.
(4) Crude oil prices are based on commercial index prices for West Texas Intermediate ("WTI") as measured on the New York Mercantile Exchange ("NYMEX") and for Louisiana Light Sweet ("LLS") as reported by Platts.

Period-to-period fluctuations in our consolidated revenues and cost of sales amounts are explained in large part by changes in energy commodity prices. Energy commodity prices fluctuate for a variety of reasons, including supply and demand imbalances and geopolitical tensions. The following is a discussion of period-to-period changes in key commodity prices affecting our results of operations:

- The weighted-average indicative market price for NGLs (based on prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production) was $1.03 per gallon during the second quarter of 2014 versus $0.95 per gallon during the second quarter of 2013 – an 8% quarter-to-quarter increase. Ethane accounts for the largest volume of NGLs extracted from the natural gas stream. The price of ethane averaged $0.29 per gallon during the second quarter of 2014 compared to $0.27 per gallon during the second quarter of 2013. The weighted-average indicative market price for NGLs was $1.08 per gallon during the first six months of 2014 versus $0.99 per gallon during the first six months of 2013 – a 9% period-to-period increase. The price of ethane averaged $0.31 per gallon during the first six months of 2014 compared to $0.27 per gallon during the first six months of 2013. According to U.S. Energy Information Administration statistics, ethane volumes account for approximately 35% of NGLs produced from natural gas processing activities. As a result of producers allocating more of their capital budgets to developing NGL-rich shale plays and their success in extracting such resources, ethane production has increased more rapidly than the ethylene industry's current capability to consume the increase in supplies.

- The market price of natural gas (as measured at the Henry Hub in Louisiana) averaged $4.68 per MMBtu during the second quarter of 2014 versus $4.10 per MMBtu during the second quarter of 2013 – a 14% quarter-to-quarter increase. The market price of natural gas (as measured at the Henry Hub in Louisiana) averaged $4.81 per MMBtu during the first six months of 2014 versus $3.72 per MMBtu during the first six months of 2013 – a 29% period-to-period increase. The increase in price is generally due to higher natural gas demand for power generation and as a heating fuel.

- The market price of WTI crude oil (as measured on the NYMEX) averaged $102.99 per barrel during the second quarter of 2014 compared to $94.22 per barrel during the second quarter of 2013 – a 9% quarter-to-quarter increase. The market price of WTI crude oil (as measured on the NYMEX) averaged $100.84 per barrel during the first six months of 2014 compared to $94.30 per barrel during the first six months of 2013 – a 7% period-to-period increase. As a result of our recent crude oil pipeline infrastructure improvements, we have greater access to U.S. Gulf Coast refiners. Typically, these refining customers purchase crude oil based on LLS prices, which are significantly higher than WTI prices. Although down period-to-period, LLS prices averaged $105.55 per barrel during the second quarter of 2014 compared to $104.63 per barrel during the second quarter of 2013 and $104.99 per barrel during the first six months of 2014 compared to $109.28 per barrel during the first six months of 2013.

A decrease in our consolidated marketing revenues due to lower energy commodity sales prices may not result in a decrease in gross operating margin or cash available for distribution, since our consolidated cost of sales amounts would also be lower due to comparable decreases in the purchase prices of the underlying energy commodities. The same correlation would be true in the case of higher energy commodity sales prices and purchase costs.

We attempt to mitigate any commodity price exposure through our hedging activities as well as through converting keepwhole and similar contracts to fee-based arrangements. See Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for information regarding our commodity hedging activities.

Consolidated Income Statement Highlights

The following information highlights significant changes in our comparative income statement amounts and the primary drivers of such changes.

Revenues for the second quarter of 2014 increased $1.37 billion when compared to the second quarter of 2013. Revenues from the marketing of crude oil increased a net $727.5 million quarter-to-quarter primarily due to higher sales volumes, which accounted for a $1.26 billion increase, partially offset by lower sales prices, which accounted for a $531.1 million decrease. Revenues from the marketing of NGLs increased $394.7 million quarter-to-quarter primarily due to higher sales prices, which accounted for a $248.1 million increase, and higher sales volumes, which accounted for an additional $146.6 million increase. Collectively, revenues from the marketing of natural gas and petrochemical and refined products increased a net $160.2 million quarter-to-quarter primarily due to higher sales prices, which accounted for a $267.9 million increase, partially offset by lower sales volumes, which accounted for a $107.7 million decrease. Revenues from the marketing of octane additives and high purity isobutylene ("HPIB") decreased a net $68.8 million quarter-to-quarter primarily due to lower sales volumes, which accounted for an $87.6 million decrease, partially offset by higher sales prices, which accounted for an $18.8 million increase. Revenues from midstream services increased $143.9 million quarter-to-quarter primarily due to contributions from recently completed assets such as the ATEX pipeline, the Rocky Mountain expansion of our Mid-America Pipeline System as well as certain assets at our Mont Belvieu complex.

For the six months ended June 30, 2014, revenues increased $2.9 billion when compared to the six months ended June 30, 2013. Revenues from the marketing of crude oil increased a net $857.9 million period-to-period primarily due to higher sales volumes, which accounted for a $2.47 billion increase, partially offset by lower sales prices, which accounted for a $1.61 billion decrease. Revenues from the marketing of NGLs increased $1.52 billion period-to-period primarily due to higher sales prices, which accounted for a $1.16 billion increase, and higher sales volumes, which accounted for an additional $364.2 million increase. Collectively, revenues from the marketing of natural gas and refined products increased a net $502.1 million period-to-period primarily due to higher sales prices, which accounted for a $614.7 million increase, partially offset by lower sales volumes, which accounted for a $112.6 million decrease. Revenues from the marketing of petrochemical products decreased a net $32.9 million period-to-period primarily due to lower sales volumes, which accounted for an $80.4 million decrease, partially offset by higher sales prices, which accounted for a $47.5 million increase. Revenues from the marketing of octane additives and HPIB decreased a net $223.0 million period-to-period primarily due to lower sales volumes, which in turn were primarily due to lower production volumes caused by unscheduled plant maintenance outages. Revenues from midstream services increased $287.3 million period-to-period primarily due to contributions from recently completed assets such as the ATEX pipeline, the Rocky Mountain expansion of our Mid-America Pipeline System as well as certain assets in the Eagle Ford Shale and at our Mont Belvieu complex.

Total operating costs and expenses for the second quarter of 2014 increased $1.27 billion when compared to the second quarter of 2013 primarily due to a $1.25 billion increase in cost of sales. Cost of sales associated with our marketing of crude oil increased a net $788.6 million quarter-to-quarter primarily due to higher sales volumes, which accounted for a $1.22 billion increase, partially offset by lower purchase costs, which accounted for a $436.1 million decrease. The cost of sales associated with our marketing of NGLs increased $391.1 million quarter-to-quarter primarily due to higher purchase prices, which accounted for a $294.2 million increase, and sales volumes, which accounted for an additional $96.9 million increase. Collectively, the cost of sales associated with our marketing of natural gas and petrochemical and refined products increased a net $118.7 million quarter-to-quarter primarily due to higher purchase prices, which accounted for a $240.0 million increase, partially offset by lower sales volumes, which accounted for a $121.3 million decrease. Cost of sales associated with our marketing of octane additives and HPIB decreased $52.6 million quarter-to-quarter primarily due to lower purchase costs, which accounted for a $36.1 million decrease, and lower sales volumes, which accounted for an additional $16.5 million decrease.

Other operating costs and expenses increased $38.1 million quarter-to-quarter primarily due to higher costs for maintenance and utilities. Depreciation, amortization and accretion expenses in operating costs and expenses increased $22.7 million for the second quarter of 2014 when compared to the second quarter of 2013 primarily due to recently constructed assets being placed into service. We recorded net gains within operating costs and expenses of $6.8 million attributable to asset sales in the second quarter of 2014 compared to net losses of $5.7 million in the second quarter of 2013.

For the six months ended June 30, 2014, total operating costs and expenses increased $2.73 billion when compared to the six months ended June 30, 2013 primarily due to a $2.61 billion increase in cost of sales. Cost of sales associated with our marketing of crude oil increased a net $946.5 million period-to-period primarily due to higher sales volumes, which accounted for a $2.37 billion increase, partially offset by lower purchase costs, which accounted for a $1.42 billion decrease. The cost of sales associated with our marketing of NGLs increased $1.39

billion period-to-period primarily due to higher purchase prices, which accounted for a $1.12 billion increase, and sales volumes, which accounted for an additional $271.2 million increase. Collectively, the cost of sales associated with our marketing of natural gas and petrochemical and refined products increased a net $393.1 million period-to-period primarily due to higher purchase prices, which accounted for a $600.4 million increase, partially offset by lower sales volumes, which accounted for a $207.3 million decrease. Cost of sales associated with our marketing of octane additives and HPIB decreased $133.4 million period-to-period primarily due to lower purchase costs, which accounted for a $67.8 million decrease, and lower sales volumes, which accounted for an additional $65.6 million decrease.

Other operating costs and expenses increased $141.3 million period-to-period primarily due to (i) higher overall costs for maintenance and utilities, which accounted for $65.2 million of the increase, (ii) a negative variance of $31.1 million period-to-period attributable to $9.7 million of volumetric measurement losses in the first six months of 2014 compared to $21.4 million of volumetric measurement gains in the first six months of 2013, and (iii) a $16.6 million benefit recognized in the first quarter of 2013 attributable to reductions in a provision for pipeline capacity obligations associated with our refined products terminals. Depreciation, amortization and accretion expenses in operating costs and expenses increased $47.3 million for the first six months of 2014 when compared to the first six months of 2013 primarily due to recently constructed assets being placed into service.

We recorded net gains within operating costs and expenses of $96.4 million attributable to asset sales and insurance recoveries in the first six months of 2014 compared to $58.2 million in the first six months of 2013. We recognized $95.0 million of gains attributable to the receipt of nonrefundable cash insurance proceeds related to our West Storage claims in the first quarter of 2014 compared to $8.8 million of such gains in the first quarter of 2013. These proceeds were attributable to property damage claims we filed in connection with the February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. In March 2013, we sold the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, along with a related storage cavern, and recognized a $52.5 million gain on the sale.

General and administrative costs for the second quarter of 2014 increased $2.2 million when compared to the second quarter of 2013. For the six months ended June 30, 2014, general and administrative costs increased $5.9 million when compared to the same period in 2013 primarily due to higher employee compensation expenses as well as costs we incurred during the first quarter of 2014 related to the settlement of litigation associated with Enterprise GP Holdings L.P.

Equity income from our unconsolidated affiliates increased $12.7 million for the second quarter of 2014 and $24.7 million for the six months ended June 30, 2014 when compared to the same respective periods in 2013. These increases were primarily due to increased earnings from our investments in crude oil pipeline joint ventures.

Interest expense increased $28.7 million for the second quarter of 2014 and $53.7 million for the six months ended June 30, 2014 when compared to the same respective periods in 2013. The following table presents the components of our consolidated interest expense for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
Interest charged on debt principal outstanding	$ 240.4	$ 229.7	$ 473.3	$ 452.9
Impact of interest rate hedging program, including related amortization	1.6	1.5	3.0	0.5
Interest costs capitalized in connection with construction projects (1)	(17.7)	(35.7)	(36.2)	(67.3)
Other (2)	4.6	4.7	9.7	10.0
Total	$ 228.9	$ 200.2	$ 449.8	$ 396.1

(1) Capitalized interest amounts become part of the historical cost of an asset and are charged to earnings (as a component of depreciation expense) ratably over the estimated useful life of the asset once the asset enters its intended service. Capitalized interest amounts fluctuate from period-to-period based on the timing of when projects are placed into service, our capital spending levels and the interest rates charged on borrowings.
(2) Primarily reflects facility commitment fees charged in connection with our revolving credit facilities and amortization of debt issuance costs.

Interest charged on debt principal outstanding, which is the primary driver of interest expense, increased a net $10.7 million quarter-to-quarter generally due to increased debt principal amounts outstanding during the second quarter of 2014, which accounted for a $17.8 million increase, partially offset by the effect of lower overall interest rates in the second quarter of 2014, which accounted for a $7.1 million decrease. Our weighted-average debt principal balance for the second quarter of 2014 was $18.38 billion compared to $17.15 billion for the second quarter of 2013. In general, our debt principal balances have increased over time due to the partial debt financing of our capital spending program. For a discussion of our consolidated debt obligations and capital spending program, see "Liquidity and Capital Resources" within this Part I, Item 2.

For the six months ended June 30, 2014, interest charged on debt principal outstanding increased a net $20.4 million period-to-period generally due to increased debt principal amounts outstanding during the first six months of 2014, which accounted for a $34.6 million increase, partially offset by the effect of lower overall interest rates in the first six months of 2014, which accounted for a $14.2 million decrease. Our weighted-average debt principal balance for the first six months of 2014 was $18.03 billion compared to $16.9 billion for the first six months of 2013.

Provision for income taxes decreased $10.4 million for the second quarter of 2014 and $12.0 million for the six months ended June 30, 2014 when compared to the same respective periods in 2013. These decreases were primarily due to changes in our accruals for state tax obligations under the Revised Texas Franchise Tax (or "Texas Margin Tax").

Business Segment Highlights

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. As presented in the table below, total gross operating margin was $1.26 billion for the second quarter of 2014 compared to $1.14 billion for the second quarter of 2013. For the six months ended June 30, 2014 and 2013, total gross operating margin was $2.59 billion and $2.37 billion, respectively.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Non-GAAP gross operating margin by segment:				
NGL Pipelines & Services	$ 680.9	$ 544.9	$ 1,460.9	$ 1,137.4
Onshore Natural Gas Pipelines & Services	203.0	197.7	423.4	388.5
Onshore Crude Oil Pipelines & Services	184.0	197.2	343.7	433.6
Offshore Pipelines & Services	33.6	39.7	72.9	80.2
Petrochemical & Refined Products Services	161.7	162.7	292.1	333.6
Total gross operating margin	$ 1,263.2	$ 1,142.2	$ 2,593.0	$ 2,373.3

For additional information regarding our use of this non-GAAP financial measure, see "Other Items – Use of Non-GAAP Financial Measures" within this Part I, Item 2.

The following information highlights significant changes in our period-to-period segment results (i.e., gross operating margin amounts) and the primary drivers of such changes. The selected volume statistics presented in the tabular information for each segment are reported on a net basis, taking into account our ownership interests in certain joint ventures, and reflect the periods in which we owned an interest in such operations. These statistics reflect volumes for newly constructed assets from the dates such assets were placed into service.

NGL Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the NGL Pipelines & Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Segment gross operating margin:				
Natural gas processing and related NGL marketing activities	$ 265.7	$ 263.9	$ 614.9	$ 533.5
NGL pipelines and related storage	261.0	187.8	551.2	420.0
NGL fractionation	154.2	93.2	294.8	183.9
Total	$ 680.9	$ 544.9	$ 1,460.9	$ 1,137.4
Selected volumetric data:				
NGL transportation volumes (MBPD)	2,866	2,744	2,855	2,641
NGL fractionation volumes (MBPD)	845	678	819	693
Equity NGL production (MBPD) (1)	136	118	136	120
Fee-based natural gas processing (MMcf/d) (2)	4,941	4,581	4,829	4,553

(1) Represents the NGL volumes we earn and take title to in connection with our processing activities.
(2) Volumes reported correspond to the revenue streams earned by our gas plants.

Natural gas processing and related NGL marketing activities

Gross operating margin from our natural gas processing and related NGL marketing activities for the second quarter of 2014 increased $1.8 million when compared to the second quarter of 2013. In general, natural gas processing margins were lower in the second quarter of 2014 when compared to the second quarter of 2013 due to higher natural gas prices relative to NGL prices during the second quarter of 2014. Lower natural gas processing margins were more than offset by a quarter-to-quarter increase in equity NGL and fee-based processing volumes at most of our natural gas processing plants.

Gross operating margin from our Pioneer natural gas processing plant in Wyoming increased a net $16.1 million quarter-to-quarter primarily due to higher equity NGL production volumes of 9 MBPD, which accounted for an $18.6 million increase, partially offset by lower processing margins, which accounted for a $2.5 million decrease. Gross operating margin from our South Texas natural gas processing plants increased a net $9.6 million quarter-to-quarter primarily due to (i) higher processing volumes and equity NGL production, which accounted for a $5.1 million increase, (ii) higher processing fees, which accounted for a $6.7 million increase, partially offset by (iii) lower processing margins, which accounted for a $2.0 million decrease. Our South Texas gas plants continue to benefit from NGL-rich natural gas production from the Eagle Ford Shale. Equity NGL production and fee-based natural gas processing volumes at our South Texas gas plants for the second quarter of 2014 increased 5 MBPD and 190 MMcf/d, respectively, when compared to the second quarter of 2013. Collectively, gross operating margin from our gas plants in Louisiana and our Indian Basin natural gas processing plant in New Mexico increased $7.5 million quarter-to-quarter primarily due to higher volumes. Equity NGL production and fee-based natural gas processing volumes at these plants for the second quarter of 2014 increased 9 MBPD and 129 MMcf/d, respectively, when compared to the second quarter of 2013. Gross operating margin from our Meeker natural gas processing plant in Colorado decreased $8.3 million quarter-to-quarter primarily due to lower processing margins in the second quarter of 2014.

Gross operating margin from our NGL marketing activities for the second quarter of 2014 decreased a net $24.0 million when compared to the second quarter of 2013 primarily due to lower sales margins, which accounted for a $28.2 million decrease, partially offset by higher sales volumes, which accounted for a $4.0 million increase.

Gross operating margin from natural gas processing and related NGL marketing activities for the six months ended June 30, 2014 increased $81.4 million when compared to the same period in 2013. Gross operating margin from our NGL marketing activities for the first six months of 2014 increased $58.1 million when compared to the first six months of 2013 primarily due to higher sales margins, which accounted for a $40.7 million increase, and higher sales volumes, which accounted for an additional $14.5 million increase. Our NGL marketing activities benefitted from the expansion of our Houston Ship Channel LPG export terminal, which we completed in March 2013.

Gross operating margin from our Pioneer natural gas processing plant in Wyoming increased a net $26.2 million period-to-period primarily due to higher equity NGL production volumes of 11 MBPD, which accounted for a $34.4 million increase, partially offset by lower processing margins, which accounted for an $8.9 million decrease. Gross operating margin from our South Texas natural gas processing plants increased a net $20.1 million period-to-period primarily due to (i) higher processing volumes and equity NGL production, which accounted for a $13.0 million increase, (ii) higher processing fees, which accounted for a $14.3 million increase, partially offset by (iii) lower processing margins, which accounted for a $7.1 million decrease. Equity NGL production and fee-based natural gas processing volumes at our South Texas gas plants for the first six months of 2014 increased 10 MBPD and 187 MMcf/d, respectively, when compared to the first six months of 2013. Gross operating margin from our Indian Basin natural gas processing plant in New Mexico increased $4.6 million period-to-period primarily due to a 1 MBPD increase in equity NGL production and a 60 MMcf/d increase in fee-based natural gas processing volumes.

Gross operating margin from our Meeker natural gas processing plant in Colorado decreased $26.5 million period-to-period primarily due to lower processing margins in the first six months of 2014. Lastly, gross operating margin from our natural gas processing plants in Louisiana decreased a net $4.5 million period-to-period primarily due to lower fee-based revenues and processing margins, which accounted for a combined $8.7 million decrease, partially offset by a 3 MBPD increase in equity NGL production volumes, which accounted for a $4.8 million increase.

NGL pipelines and related storage

Gross operating margin from NGL pipelines and related storage assets for the second quarter of 2014 increased $73.2 million when compared to the second quarter of 2013 primarily due to the start-up of our ATEX pipeline and strong results from our South Texas assets and Mid-America Pipeline System and Seminole Pipeline. Our ATEX pipeline commenced operations in January 2014 and contributed $35.3 million of gross operating margin during the second quarter of 2014 and 44 MBPD of transportation volumes. Non-GAAP gross operating margin for ATEX for the second quarter of 2014 includes $15.4 million of transportation revenues associated with shipper make-up rights that are deferred under GAAP and not reflected in our consolidated revenues.

Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased a combined $19.3 million quarter-to-quarter primarily due to higher revenues from ship-or-pay agreements in the second quarter of 2014 associated with the expansion of our Rocky Mountain pipeline. This expansion project went into service in January 2014 and was built to accommodate growing natural gas and NGL production from major supply basins in Colorado, Utah and Wyoming. Gross operating margin from our South Texas NGL Pipeline System increased $11.4 million quarter-to-quarter primarily due to a 78 MBPD increase in transportation volumes associated with Eagle Ford Shale production.

Gross operating margin from these businesses for the six months ended June 30, 2014 increased $131.2 million when compared to the same period in 2013. Our ATEX pipeline contributed $66.0 million of gross operating margin during the first six months of 2014 and 37 MBPD of transportation volumes. Non-GAAP gross operating margin for ATEX for the first six months of 2014 includes $33.7 million of transportation revenues associated with shipper make-up rights that are deferred under GAAP and not reflected in our consolidated revenues.

Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased a combined $29.9 million period-to-period. A $55.8 million increase in revenues primarily due to higher transportation revenues from ship-or-pay agreements associated with the Rocky Mountain pipeline expansion and higher system-wide tariffs during the first six months of 2014 was partially offset by a $25.9 million increase in operating costs (e.g., increased fuel and maintenance costs). In the aggregate, transportation volumes for the Mid-America Pipeline System and Seminole Pipeline increased a net 4 MBPD period-to-period.

Gross operating margin from our South Texas NGL Pipeline System increased $23.1 million period-to-period primarily due to a 107 MBPD increase in transportation volumes associated with Eagle Ford Shale production. Gross operating margin from our Houston Ship Channel LPG export terminal and related Channel Pipeline increased a combined $5.9 million period-to-period primarily due to increased volumes. As a result of high demand for export services, loading volumes at our Houston Ship Channel LPG export terminal increased 42 MBPD period-to-period and volumes transported on the related Channel Pipeline increased 51 MBPD period-to-period.

NGL fractionation

Gross operating margin from NGL fractionation for the second quarter of 2014 increased $61.0 million when compared to the second quarter of 2013 primarily due to higher fractionation volumes and fees at our Mont Belvieu complex. Our Mont Belvieu NGL fractionators continue to benefit from increases in mixed NGL volumes produced from domestic shale plays (e.g., the Eagle Ford Shale) and other regions such as the Rocky Mountains. NGL fractionation volumes at our Mont Belvieu complex increased 179 MBPD quarter-to-quarter (net to our ownership interest), which resulted in a $46.5 million quarter-to-quarter increase in gross operating margin after taking into account associated operating costs. We placed our seventh and eighth NGL fractionators into service at our Mont Belvieu complex during the third and fourth quarters of 2013, respectively. Higher average fractionation and other fees at our Mont Belvieu NGL fractionators accounted for an additional $16.8 million quarter-to-quarter increase in gross operating margin.

Gross operating margin from NGL fractionation for the six months ended June 30, 2014 increased $110.9 million when compared to the same period in 2013 primarily due to higher fractionation volumes and fees at our Mont Belvieu complex. NGL fractionation volumes at our Mont Belvieu complex increased 138 MBPD period-to-period (net to our ownership interest), which resulted in a $72.2 million period-to-period increase in gross operating margin after taking into account associated operating costs. Higher average fractionation and other fees at our Mont Belvieu NGL fractionators accounted for an additional $36.1 million period-to-period increase in gross operating margin.

Onshore Natural Gas Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the Onshore Natural Gas Pipelines & Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
Segment gross operating margin	$ 203.0	$ 197.7	$ 423.4	$ 388.5
Selected volumetric data:				
Natural gas transportation volumes (BBtus/d)	12,617	13,307	12,569	13,189

Gross operating margin from our onshore natural gas pipelines and services segment for the second quarter of 2014 increased $5.3 million when compared to the second quarter of 2013. Gross operating margin from our natural gas marketing activities increased $2.2 million quarter-to-quarter primarily due to higher sales margins.

Gross operating margin from our Texas Intrastate System increased a net $3.1 million quarter-to-quarter primarily due to higher fees, which accounted for a $3.6 million increase, partially offset by lower transportation volumes, which accounted for a $0.5 million decrease. Natural gas transportation volumes for the Texas Intrastate System decreased 80 BBtus/d quarter-to-quarter. Gross operating margin from our Fairplay Gathering System increased $1.4 million quarter-to-quarter primarily due to higher fees, which accounted for a $1.0 million increase, and a 25 BBtus/d increase in gathering volumes, which accounted for an additional $0.5 million increase. Gross operating margin from our San Juan Gathering System increased a net $1.2 million quarter-to-quarter primarily due to lower operating costs. Gathering volumes on the San Juan Gathering System decreased 88 BBtus/d quarter-to-quarter. In addition, gross operating margin from our Central Treating Facility in Colorado increased $1.5 million quarter-to-quarter primarily due to higher volumes.

Collectively, gross operating margin from our Jonah and Piceance Basin Gathering Systems decreased $2.6 million quarter-to-quarter primarily due to a combined 318 BBtus/d decrease in gathering volumes. Lastly, gross operating margin from our Haynesville Gathering System decreased $2.2 million quarter-to-quarter primarily due to a 142 BBtus/d decrease in gathering volumes. Certain producers in the lean gas resource basins served by these three gathering systems have curtailed their drilling programs in response to the continued low price of natural gas. These producers have refocused their drilling efforts in regions with crude oil production or natural gas containing a higher NGL content (i.e., rich gas streams).

Gross operating margin from our onshore natural gas pipelines and services segment for the six months ended June 30, 2014 increased $34.9 million when compared to the same period in 2013. Gross operating margin from our natural gas marketing activities increased $21.1 million period-to-period primarily due to higher sales margins and unrealized, non-cash mark-to-market income.

Gross operating margin from our Texas Intrastate System increased $23.0 million period-to-period primarily due to higher revenues in the first six months of 2014, which accounted for a $16.0 million increase, and lower maintenance and other operating costs in the first six months of 2014, which accounted for an additional $7.0 million increase. Transportation revenues on the Texas Intrastate System increased $9.0 million period-to-period primarily due to higher average fees. In addition, firm capacity reservation fees on the Texas Intrastate System increased $4.1 million period-to-period primarily due to strong demand by producers in the Eagle Ford Shale supply basin. Natural gas transportation volumes for the Texas Intrastate System increased 51 BBtus/d period-to-period.

Gross operating margin from our San Juan Gathering System increased a net $6.4 million period-to-period primarily due to higher gathering fees, which are indexed to natural gas prices and accounted for a $9.3 million increase, partially offset by a 47 BBtus/d decrease in gathering volumes, which accounted for a $3.0 million decrease. Collectively, gross operating margin from our Jonah and Piceance Basin Gathering Systems decreased $8.0 million period-to-period primarily due to a combined 312 BBtus/d decrease in gathering volumes. Lastly, gross operating margin from our Haynesville Gathering System decreased $6.6 million period-to-period primarily due to a 170 BBtus/d decrease in gathering volumes.

Onshore Crude Oil Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the Onshore Crude Oil Pipelines & Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Segment gross operating margin	$ 184.0	$ 197.2	$ 343.7	$ 433.6
Selected volumetric data:				
Crude oil transportation volumes (MBPD)	1,297	1,145	1,279	1,073

Gross operating margin from our onshore crude oil pipelines and services segment for the second quarter of 2014 decreased $13.2 million when compared to the second quarter of 2013. Gross operating margin from our crude oil marketing and related activities decreased $52.6 million quarter-to-quarter primarily due to lower sales margins, which were primarily caused by a quarter-to-quarter decrease in regional price spreads for crude oil. For example, the average indicative price spread between LLS and WTI crude oil was $10.41 per barrel in the second quarter of 2013 compared to $2.56 per barrel in the second quarter of 2014.

Gross operating margin from our South Texas Crude Oil Pipeline System and West Texas System increased a combined $23.8 million quarter-to-quarter primarily due to an aggregate 100 MBPD increase in transportation volumes primarily from the Eagle Ford Shale and Permian Basin. Equity earnings from our investment in the Eagle Ford Crude Oil Pipeline System increased $10.4 million quarter-to-quarter on a 77 MBPD increase in transportation volumes (net to our interest). This system commenced operations during the second quarter of 2013. Gross operating margin from our investment in the Seaway Pipeline increased $5.9 million quarter-to-quarter primarily due to a tariff rate increase that went into effect in July 2013 applicable to transportation volumes on Seaway's Longhaul System. Overall, Seaway's transportation volumes decreased 43 MBPD quarter-to-quarter (net to our interest) primarily due to lower volumes on its Texas City System.

Gross operating margin from our onshore crude oil pipelines and services segment for the six months ended June 30, 2014 decreased $89.9 million when compared to the same period in 2013. Gross operating margin from our crude oil marketing and related activities decreased $163.7 million period-to-period primarily due to lower sales margins, which were primarily caused by a period-to-period decrease in regional price spreads for crude oil. For example, the average indicative price spread between LLS and WTI crude oil was $14.98 per barrel in the first six months of 2013 compared to $4.15 per barrel in the first six months of 2014.

Gross operating margin from our South Texas Crude Oil Pipeline System and West Texas System increased a combined $57.1 million period-to-period primarily due to an aggregate 97 MBPD increase in transportation volumes. Equity earnings from our investment in the Eagle Ford Crude Oil Pipeline System increased $18.9 million period-to-period on a 70 MBPD increase in transportation volumes. Gross operating margin from our investment in the Seaway Pipeline increased $5.2 million period-to-period primarily due to the tariff rate increase mentioned above. Transportation volumes on Seaway's Freeport System increased 43 MBPD period-to-period (net to our interest) primarily due to the timing of a refinery customer's turnaround activities between periods.

Offshore Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the Offshore Pipelines & Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Segment gross operating margin	$ 33.6	$ 39.7	$ 72.9	$ 80.2
Selected volumetric data:				
Natural gas transportation volumes (BBtus/d)	609	720	589	726
Platform natural gas processing (MMcf/d)	152	224	150	234
Crude oil transportation volumes (MBPD)	318	311	326	303
Platform crude oil processing (MBPD)	9	14	13	14

Gross operating margin from our offshore pipelines and services segment for the second quarter of 2014 decreased $6.1 million when compared to the second quarter of 2013. In the aggregate, gross operating margin from our Independence Hub platform and Independence Trail pipeline decreased $4.8 million quarter-to-quarter primarily due to lower platform processing and pipeline throughput volumes during the second quarter of 2014. Natural gas processing volumes on the Independence Hub platform decreased 109 MMcf/d quarter-to-quarter (87 MMcf/d net to our interest) and natural gas transportation volumes on the Independence Trail pipeline decreased 98 BBtus/d quarter-to-quarter.

Collectively, gross operating margin from our Marco Polo Oil Pipeline and equity method investment in Deepwater Gateway's Marco Polo platform decreased $1.8 million quarter-to-quarter. These assets were shut-in for repairs following a small fire on the Marco Polo platform in May 2014. The outage lasted approximately two months with the platform and pipeline resuming operations in July 2014.

Gross operating margin from this segment for the first six months of 2014 decreased $7.3 million when compared to the first six months of 2013. In the aggregate, gross operating margin from our Independence Hub platform and Independence Trail pipeline decreased $10.3 million period-to-period primarily due to lower platform processing and pipeline throughput volumes during the first six months of 2014. Natural gas processing volumes on the Independence Hub platform decreased 116 MMcf/d period-to-period (92 MMcf/d net to our interest) and natural gas transportation volumes on the Independence Trail pipeline decreased 106 BBtus/d period-to-period.

Gross operating margin from our Marco Polo Oil Pipeline and equity method investment in Deepwater Gateway's Marco Polo platform decreased $1.1 million period-to-period primarily due to the outage mentioned above. Equity earnings from our investment in the Cameron Highway Oil Pipeline increased $3.9 million period-to-period primarily due to a 29 MBPD increase (net to our interest) in crude oil transportation volumes. In addition, gross operating margin from our Shenzi Oil Pipeline increased $1.1 million period-to-period primarily due to a 5 MBPD increase in transportation volumes.

We are beginning to see crude oil volumes respond to the pick-up in producer activity in the Gulf of Mexico. Our offshore crude oil pipelines averaged 326 MBPD in the first six months of 2014, which is a continued improvement since the first quarter of 2010. Currently, there are 41 drilling ships and deepwater semi-submersible drilling rigs active in the Gulf of Mexico region (U.S. waters) and another 12 vessels are expected to arrive before the end of 2015. Approximately half of this drilling fleet will be focused on existing fields, many of which are connected to our assets.

Petrochemical & Refined Products Services. The following table presents segment gross operating margin and selected volumetric data for the Petrochemical & Refined Products Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
Segment gross operating margin:				
Propylene fractionation and related activities	$ 42.0	$ 26.1	$ 91.0	$ 61.1
Butane isomerization and related operations	32.0	27.4	54.2	50.8
Octane enhancement and related plant operations	46.3	43.0	46.5	81.3
Refined products pipelines and related activities	23.5	48.7	66.1	105.3
Marine transportation and other	17.9	17.5	34.3	35.1
Total	$ 161.7	$ 162.7	$ 292.1	$ 333.6
Selected volumetric data:				
Propylene fractionation volumes (MBPD)	71	71	72	70
Butane isomerization volumes (MBPD)	105	97	93	91
Standalone DIB processing volumes (MBPD)	83	68	79	59
Octane additive and related plant production volumes (MBPD)	20	20	13	18
Transportation volumes, primarily refined products and petrochemicals (MBPD)	756	688	730	684

Propylene fractionation and related activities

Gross operating margin from our propylene fractionation and related activities for the second quarter of 2014 increased $15.9 million when compared to the second quarter of 2013. Likewise, gross operating margin increased $29.9 million for the six months ended June 30, 2014 when compared to the same period in 2013. These increases were primarily due to higher propylene sales margins during 2014.

Butane isomerization and deisobutanizer operations

Gross operating margin from these operations increased an aggregate $4.6 million for the second quarter of 2014 when compared to the second quarter of 2013. Gross operating margin from butane isomerization increased $4.4 million quarter-to-quarter. A $7.6 million quarter-to-quarter increase in isomerization revenues and by-product sales, which was primarily due to higher volumes, was partially offset by higher maintenance and other operating expenses, which accounted for a $3.2 million decrease. Gross operating margin from our standalone deisobutanizers ("DIBs"), which are used to process mixed butanes from our NGL fractionation operations, increased $0.3 million quarter-to-quarter.

Gross operating margin from our butane isomerization and deisobutanizer operations increased an aggregate $3.4 million for the first six months of 2014 when compared to the same period in 2013. Gross operating margin from butane isomerization increased $0.8 million period-to-period. A $3.0 million increase in isomerization revenues primarily due to higher fees and a $3.3 million increase primarily due to higher by-product sales volumes were partially offset by higher maintenance and other operating expenses, which accounted for a $5.5 million decrease.

Gross operating margin from our standalone DIBs increased $2.7 million period-to-period. We added a new DIB unit at our Mont Belvieu facility in March 2013, which accounted for $2.5 million of the period-to-period increase in gross operating margin and an 18 MBPD period-to-period increase in processing volumes.

Octane enhancement and HPIB plant operations

Gross operating margin from our octane enhancement facility and HPIB plant increased a combined $3.3 million quarter-to-quarter. The increase in gross operating margin is primarily due to lower catalyst-related and other operating costs in the second quarter of 2014 compared to the second quarter of 2013.

Gross operating margin from these businesses decreased a combined $34.8 million for the first six months of 2014 compared to the same period in 2013. The period-to-period decrease in gross operating margin is primarily due to an extended period of unscheduled maintenance at the octane enhancement facility during the first quarter of 2014.

Refined products pipelines and related activities

Gross operating margin from our refined products pipelines and related marketing activities for the second quarter of 2014 decreased $25.2 million when compared to the second quarter of 2013. The quarter-to-quarter decrease in gross operating margin is primarily due to a $24.3 million benefit recognized in the second quarter of 2013 in connection with the settlement of a rate case involving the TE Products Pipeline. Overall, transportation volumes for the TE Products Pipeline increased a net 59 MBPD quarter-to-quarter due to higher intrastate shipments of petrochemicals and refined products in southeast Texas, which accounted for a combined 101 MBPD increase, partially offset by lower interstate transportation volumes of 42 MBPD. Components of the TE Products Pipeline were repurposed to accommodate the southbound delivery of ethane on our ATEX pipeline, which resulted in lower interstate transportation volumes on the TE Products Pipeline during the second quarter of 2014 when compared to the second quarter of 2013. The results for our ATEX pipeline, which commenced operations in January 2014, are reported under the NGL Pipelines & Services business segment.

Gross operating margin from our refined products pipelines and related marketing activities for the first six months of 2014 decreased $39.2 million when compared to the same period of 2013. The period-to-period decrease is primarily due to (i) a $16.6 million benefit recorded in the first quarter of 2013 related to reductions in a provision for future pipeline capacity obligations involving our refined products terminals and (ii) a net $12.6 million decrease in transportation revenues on the TE Products Pipeline attributable to lower interstate transportation volumes for refined products and NGLs associated with construction of the ATEX pipeline. In addition, of the $24.3 million benefit recorded in the second quarter of 2013 for the rate case settlement (as mentioned above), approximately $8.0 million was attributable to periods prior to the first six months of 2013. Overall, transportation volumes for the TE Products Pipeline increased a net 39 MBPD period-to-period primarily due to higher intrastate shipments of petrochemicals and refined products in southeast Texas, which accounted for a combined 77 MBPD increase, partially offset by lower interstate transportation volumes for refined products and NGLs of 38 MBPD.

Liquidity and Capital Resources

At June 30, 2014, we had $3.74 billion of consolidated liquidity, which was comprised of $242.0 million of unrestricted cash on hand and approximately $3.5 billion of available borrowing capacity under EPO's revolving credit facility. Based on current market conditions (as of the filing date of this quarterly report), we believe we will have sufficient liquidity, cash flow from operations and access to capital markets to fund our capital expenditures and working capital needs.

We expect to issue additional equity and debt securities to assist us in meeting our future liquidity requirements, including those related to capital spending. We have a universal shelf registration statement (the "2013 Shelf") on file with the SEC. The 2013 Shelf allows Enterprise Products Partners L.P. and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively.

Consolidated Debt

We had $18.38 billion of principal amounts outstanding under consolidated debt agreements at June 30, 2014. The following table presents scheduled maturities of our consolidated debt obligations outstanding at June 30, 2014 for the periods indicated (dollars in millions):

		Scheduled Maturities of Debt					
	Total	Remainder of 2014	2015	2016	2017	2018	After 2018
Senior Notes	$ 16,850.0	$ 650.0	$ 1,300.0	$ 750.0	$ 800.0	$ 350.0	$ 13,000.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	$ 18,382.7	$ 650.0	$ 1,300.0	$ 750.0	$ 800.0	$ 350.0	$ 14,532.7

We expect to refinance the remaining current maturities of our consolidated debt obligations at or prior to their maturity. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for additional information regarding our consolidated debt.

In February 2014, EPO issued $850 million in principal amount of 3.90% senior notes due February 2024 ("Senior Notes JJ") and $1.15 billion in principal amount of 5.10% senior notes due February 2045 ("Senior Notes KK"). Senior Notes JJ were issued at 99.811% of their principal amount and Senior Notes KK were issued at 99.845% of their principal amount. Proceeds from the issuance of Senior Notes JJ and KK were used to repay debt, including amounts then outstanding under EPO's commercial paper program (which EPO used to repay $500.0 million in principal amount of Senior Notes O that matured in January 2014) and for general company purposes.

Enterprise Products Partners L.P. has unconditionally guaranteed Senior Notes JJ and KK on an unsecured and unsubordinated basis. These senior notes rank equal with EPO's existing and future unsecured and unsubordinated indebtedness and are senior to any existing and future subordinated indebtedness of EPO. These senior notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions.

Issuance of Common Units

The following information describes significant transactions that affected our partners' equity accounts during the six months ended June 30, 2014:

At-The-Market Program. We have a registration statement on file with the SEC covering the issuance of up to $1.25 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to this "at-the-market" program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers' transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. During the six months ended June 30, 2014, we issued 795,167 common units under this program for aggregate gross proceeds of $58.3 million. After taking into account applicable costs, these transactions resulted in net cash proceeds of $57.7 million. After taking into account the aggregate sale price of common units sold under our at-the-market program through June 30, 2014, we have the capacity to issue additional common units under this program up to an aggregate sales price of $1.19 billion.

DRIP and EUPP. We issued a total of 2,445,439 common units under our distribution reinvestment plan ("DRIP") during the six months ended June 30, 2014, which generated net cash proceeds of $160.4 million. After taking into account the number of common units issued under the DRIP through June 30, 2014, we have the capacity to issue an additional 16,035,439 common units under this plan.

In January 2014, privately held affiliates of EPCO expressed their willingness to consider purchasing through the DRIP a total of $100 million of our common units during 2014. During the six months ended June 30, 2014, these EPCO affiliates reinvested $50.0 million, resulting in the issuance of 761,487 common units under our

DRIP (this amount being a component of the total common units issued under the DRIP for the six months ended June 30, 2014). In August 2014, these EPCO affiliates reinvested an additional $25 million through the DRIP.

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of our common units in connection with our employee unit purchase plan ("EUPP"). We issued 74,530 common units under our EUPP during the six months ended June 30, 2014, which generated net cash proceeds of $5.2 million. After taking into account the number of common units issued under the EUPP through June 30, 2014, we may issue an additional 3,638,914 common units under this plan.

Use of proceeds. The net cash proceeds we received from the issuance of common units during the six months ended June 30, 2014 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and for general company purposes.

For additional information regarding our issuance of common units and related registration statements, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Two-for-One Split of Limited Partner Units

In July 2014, we announced that our general partner approved a two-for-one split of our common units. The common unit split will be accomplished by distributing one additional common unit for each common unit outstanding. The additional common units will be distributed on August 21, 2014 to holders of record as of the close of business on August 14, 2014. See Note 18 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report for additional information regarding this subsequent event.

Credit Ratings

As of August 11, 2014, the investment-grade credit ratings of EPO's long-term senior unsecured debt securities were BBB+ from Standard and Poor's and Baa1 from Moody's. In addition, the credit ratings of EPO's short-term senior unsecured debt securities were A-2 from Standard and Poor's and P-2 from Moody's. Fitch Ratings issued non-solicited ratings of BBB+ and F-2 for EPO's long-term senior unsecured debt securities and short-term senior unsecured debt securities, respectively.

EPO's credit ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any of our securities. A credit rating can be revised upward or downward or withdrawn at any time by a rating agency, if it determines that circumstances warrant such a change. A credit rating from one rating agency should be evaluated independently of credit ratings from other rating agencies.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods indicated (dollars in millions). For additional information regarding our cash flow amounts, please refer to the Unaudited Condensed Statements of Consolidated Cash Flows included under Part I, Item 1 of this quarterly report.

	For the Six Months Ended June 30,	
	2014	**2013**
Net cash flows provided by operating activities	$ 1,871.9	$ 1,530.9
Cash used in investing activities	1,554.9	1,802.6
Cash provided by (used in) financing activities	(131.9)	300.9

Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide products and services to producers and consumers of natural gas, NGLs, crude oil, refined products and petrochemicals. The products that we process, sell, transport or store are principally used as fuel for residential, agricultural and commercial heating; as feedstocks in petrochemical manufacturing; by crude oil refineries; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows. For a more complete discussion of these and other risk factors pertinent to our business, see "Risk Factors" under Part I, Item 1A of our 2013 Form 10-K.

Comparison of Six Months Ended June 30, 2014 with Six Months Ended June 30, 2013

The following information highlights significant period-to-period fluctuations in our consolidated cash flow amounts:

***Operating Activities*.** Net cash flows provided by operating activities for the first six months of 2014 increased $341.0 million when compared to the first six months of 2013. The increase in cash provided by operating activities was primarily due to:

§ a $210.6 million period-to-period increase in cash attributable to the timing of cash receipts and disbursements related to operations;

§ a $92.6 million increase in cash attributable to higher partnership income in the first six months of 2014 compared to the first six months of 2013 (after adjusting our $144.6 million period-to-period increase in net income for changes in the non-cash items identified on our Unaudited Condensed Statements of Consolidated Cash Flows); and

§ a $37.8 million period-to-period increase in cash distributions from unconsolidated affiliates primarily due to improved results from our investments in crude oil pipeline joint ventures.

For information regarding significant period-to-period changes in our consolidated net income and underlying segment results, see "Results of Operations" within this Part I, Item 2.

***Investing Activities*.** Cash used in investing activities for the first six months of 2014 decreased $247.7 million when compared to the first six months of 2013. Capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs, decreased $259.9 million period-to-period (see "Capital Spending" within this Part I, Item 2 for additional information regarding our capital spending program). Investments in unconsolidated affiliates decreased $49.1 million period-to-period, primarily due to completion of construction of the Texas Express Pipeline.

Proceeds from asset sales and insurance recoveries decreased $86.0 million period-to-period. The first six months of 2014 includes $95.0 million of nonrefundable insurance proceeds attributable to a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. These proceeds represent the final installments on these property damage claims. The first six months of 2013 includes $8.8 million of nonrefundable insurance proceeds attributable to this incident. Proceeds from asset sales during the first six months of 2013 totaled $190.4 million compared to $18.2 million for the first six months of 2014. Transactions in the first six months of 2013 included $86.9 million from the sale of the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, $35.3 million we received from the sale of lubrication oil and specialty chemical distribution assets, $29.5 million we received from the sale of chemical trucking assets and $14.9 million we received from the sale of certain marine transportation assets.

***Financing Activities*.** Our net cash outflow for financing activities during the first six months of 2014 was $131.9 million compared to a net cash inflow from financing activities in the first six months of 2013 of $300.9 million. The $432.8 million period-to-period decrease in cash flow from financing activities was primarily due to:

§ net cash proceeds from the issuance of common units decreased $612.1 million period-to-period. We issued an aggregate 3,315,136 common units in connection with our DRIP, EUPP and at-the-market program during the first six months of 2014, which generated $223.3 million of net cash proceeds. This compares to an aggregate 15,407,341 common units we issued in connection with an underwritten offering and our DRIP, EUPP and at-the-market program during the first six months of 2013, which collectively generated $835.4 million of net cash proceeds;

§ cash distributions paid to limited partners during the first six months of 2014 increased $116.5 million when compared to the first six months of 2013 due to increases in both the number of distribution-bearing common units outstanding and the quarterly cash distribution rates per unit;

§ cash contributions from noncontrolling interests decreased $91.9 million period-to-period primarily due to contributions we received during the second quarter of 2013 in connection with a joint venture involving NGL fractionators at our complex in Mont Belvieu, Texas; partially offset by

§ net borrowings under our consolidated debt agreements increased $238.6 million period-to-period. EPO issued $2.0 billion and repaid $500.0 million in principal amount of senior notes during the first six months of 2014, compared to the issuance of $2.25 billion and repayment of $1.2 billion in principal amount of senior notes during the first six months of 2013. In addition, net repayments under EPO's commercial paper program and revolving credit facility increased $213.0 million period-to-period; and

§ cash outflows related to the monetization of interest rate derivative instruments of $168.8 million during the first six months of 2013. There were no such transactions during the first six months of 2014.

Cash Distributions to Limited Partners

Our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash, after any cash reserves established by Enterprise GP in its sole discretion. Cash reserves include those for the proper conduct of our business including, for example, those for capital expenditures, debt service, working capital, operating expenses, commitments and contingencies and other significant amounts. The retention of cash by the partnership allows us to reinvest in our growth and reduce our future reliance on the equity and debt capital markets. Based on the level of available cash, management proposes a quarterly cash distribution rate to the Board of Directors of Enterprise GP, which has sole authority in approving such matters. Unlike most master limited partnerships, our general partner has a non-economic ownership interest in us and is not entitled to receive any cash distributions from us based on incentive distribution rights or other equity interests.

We measure available cash by reference to distributable cash flow. The following table summarizes our calculation of distributable cash flow for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Net income attributable to limited partners (1)	$ 637.7	$ 552.5	$ 1,436.5	$ 1,306.0
Adjustments to GAAP net income attributable to limited partners to derive non-GAAP distributable cash flow:				
Add depreciation, amortization and accretion expenses	331.1	307.8	651.0	599.8
Add asset impairment charges	3.7	27.1	12.5	38.1
Add losses or subtract gains attributable to asset sales and insurance recoveries, net	(6.8)	5.7	(96.4)	(58.2)
Add cash proceeds from asset sales and insurance recoveries (2)	16.9	68.7	113.2	199.2
Add cash distributions received from unconsolidated affiliates (3)	85.4	68.0	157.1	119.3
Subtract equity in income of unconsolidated affiliates (3)	(50.3)	(37.6)	(106.8)	(82.1)
Subtract sustaining capital expenditures (4)	(76.9)	(74.8)	(155.2)	(132.1)
Subtract losses from monetization of interest rate derivative instruments accounted for as cash flow hedges (5)	--	--	--	(168.8)
Add deferred income tax expense or subtract benefit, as applicable	0.4	21.3	0.6	14.8
Other, net	12.6	(14.0)	28.3	(14.3)
Distributable cash flow	$ 953.8	$ 924.7	$ 2,040.8	$ 1,821.7
Total cash distributions paid to limited partners with respect to period	$ 661.0	$ 606.4	$ 1,311.5	$ 1,200.7
Cumulative quarterly cash distributions per unit declared by Enterprise GP with respect to period (6)	$ 0.72	$ 0.68	$ 1.43	$ 1.35
Total distributable cash flow retained by partnership with respect to period (7)	$ 292.8	$ 318.3	$ 729.3	$ 621.0
Distribution coverage ratio (8)	1.4x	1.5x	1.6x	1.5x

(1) For a discussion of significant changes in our comparative income statement amounts underlying net income attributable to limited partners, along with the primary drivers of such changes, see "Consolidated Income Statements Highlights" within this Part I, Item 2.
(2) For a discussion of significant changes in cash proceeds from asset sales and insurance recoveries as presented in the investing activities section of our Unaudited Condensed Statements of Consolidated Cash Flows, see "Cash Flows from Operating, Investing and Financing Activities" within this Part I, Item 2.
(3) For information regarding our unconsolidated affiliates, see Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1.
(4) For a discussion of our capital spending activity, see "Capital Spending" within this Part I, Item 2. Sustaining capital expenditures for each period include accruals.
(5) For information regarding these losses, see "Interest Rate Hedging Activities" under Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1.
(6) See Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 for additional information regarding our quarterly cash distributions declared with respect to the periods presented.
(7) At the sole discretion of Enterprise GP, cash retained by the partnership with respect to each of these years was primarily reinvested in our growth capital spending program, which substantially reduced our reliance on the equity and debt capital markets to fund such major expenditures.
(8) Distribution coverage ratio determined by dividing distributable cash flow by total cash distributions paid to limited partners and in connection with distribution equivalent rights with respect to period.

For additional information regarding non-GAAP distributable cash flow, see "Other Items – Use of Non-GAAP Financial Measures" within this Part I, Item 2. Our use of distributable cash flow for the limited purposes described above and in this report is not a substitute for net cash flows provided by operating activities, the most comparable GAAP measure.

Capital Spending

An important part of our business strategy involves expansion through growth capital projects, business combinations and investments in joint ventures. We believe that we are positioned to continue to expand our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountains, Mid-Continent, Northeast and

U.S. Gulf Coast regions, including the Niobrara, Barnett, Eagle Ford, Permian, Haynesville, Marcellus and Utica Shale plays and deepwater Gulf of Mexico production fields.

Although our current focus is on expansion through growth capital projects, management continues to analyze potential business combinations, asset acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In past years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We believe this trend will continue and we expect independent oil and natural gas companies to consider similar divestitures.

We placed approximately $3.4 billion of major capital projects into service during the first six months of 2014. These projects included the ATEX pipeline, Rocky Mountain expansion of our Mid-America Pipeline System and the Seaway Pipeline looping project. We expect to complete construction and begin commercial operations of growth capital projects costing approximately $820 million during the remainder of 2014. These projects include:

§ a crude oil pipeline extending from the ECHO terminal to the Beaumont/Port Arthur, Texas area (completed in July 2014);

§ SEKCO crude oil pipeline (completed in July 2014); and

§ various product handling projects (e.g., natural gasoline treating and degassing) at our Mont Belvieu complex (expected completion in fourth quarter of 2014).

At June 30, 2014, we had approximately $1.1 billion in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction projects in Texas.

Comparison of Six Months Ended June 30, 2014 with Six Months Ended June 30, 2013

The following table summarizes our cash capital spending amounts for the periods indicated (dollars in millions):

	For the Six Months Ended June 30,	
	2014	2013
Capital spending for property, plant and equipment, net: (1)		
Growth capital projects (2)	$ 1,019.5	$ 1,296.1
Sustaining capital projects (3)	153.0	136.3
Investments in unconsolidated affiliates	498.8	547.9
Other investing activities	6.0	--
Total capital spending	$ 1,677.3	$ 1,980.3

(1) On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction projects and production well tie-ins. Contributions in aid of construction costs were $13.9 million and $14.9 million for the six months ended June 30, 2014 and 2013, respectively. Growth and sustaining capital amounts presented in the table above are presented net of related contributions in aid of construction costs.
(2) Growth capital projects either (a) result in new sources of cash flow due to enhancements of or additions to existing assets (e.g., additional revenue streams, cost savings resulting from debottlenecking of a facility, etc.) or (b) expand our asset base through construction of new facilities that will generate additional revenue streams and cash flows.
(3) Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues or result in significant cost savings.

Period-to-period fluctuations in our capital spending for growth capital projects and investments in unconsolidated affiliates are explained in large part by increases or decreases in spending on our major growth capital projects. Period-to-period fluctuations in our capital spending for sustaining capital projects are explained in large part by the timing and cost of pipeline integrity and similar projects. Our most significant growth capital expenditures for the six months ended June 30, 2014 and 2013 involved projects in the Eagle Ford Shale, at our Mont Belvieu complex, to expand joint venture crude oil pipelines, for the ATEX and Aegis ethane pipelines and for the Rocky Mountain expansion of our Mid-America Pipeline System.

Capital spending for property, plant and equipment for the first six months of 2014 decreased $259.9 million compared to the same period of 2013, with growth capital expenditures accounting for $276.6 million of the period-to-period decrease. Sustaining capital expenditures increased slightly period-to-period.

Growth capital spending for projects at our Mont Belvieu complex and in the Eagle Ford Shale decreased a combined $329.4 million period-to-period. Since 2010, expansion of midstream infrastructure in the Eagle Ford Shale region has been a key strategic focus for us. We constructed new NGL, natural gas and crude oil pipelines and the Yoakum natural gas processing plant to facilitate production growth from Eagle Ford Shale producers. Our build-out in this supply basin was substantially completed during 2013 with several projects completed in phases prior to 2013. Likewise, we completed and placed into service the seventh and eight NGL fractionators at our Mont Belvieu complex in September 2013 and November 2013, respectively.

Growth capital spending for our ATEX ethane pipeline decreased $117.3 million period-to-period. This pipeline was placed into service in January 2014. Capital spending on our Aegis ethane pipeline and projects involving the TE Products Pipeline, including its related terminals, increased a combined $176.1 million period-to-period. Aegis originates at our Mont Belvieu, Texas storage complex and is expected to have a transportation capacity of up to 425 MBPD of purity ethane volumes. Aegis is expected to commence full operations by the end of 2015.

Investments in unconsolidated affiliates for the first six months of 2014 decreased $49.1 million when compared to the same period of 2013. Our spending on the expansion and construction of joint venture crude oil pipelines increased $85.4 million, which was more than offset by a period-to-period decrease in spending related to our construction of the Texas Express Pipeline, Texas Express Gathering System and Front Range Pipeline.

Capital Spending Outlook

We currently expect total capital spending for 2014 to be in the range of $3.7 billion to $4.1 billion, which includes $350 million for sustaining capital expenditures. Our forecast of capital spending for 2014 is based on our announced strategic operating and growth plans (through the filing date of this quarterly report), which are dependent upon our ability to generate the required funds from either operating cash flows or other means, including borrowings under debt agreements and the issuance of additional equity and debt securities. We may revise our forecast of capital spending due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast of capital spending may change as a result of decisions made by management at a later date, which may include the addition of costs in connection with unforeseen acquisition opportunities.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a principal factor in determining how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future growth needs and, although we currently expect to make the forecast capital expenditures noted above, we may adjust the timing and amounts of projected expenditures in response to changes in capital market conditions.

Pipeline Integrity Costs

Our pipelines are subject to safety programs administered by the U.S. Department of Transportation ("DOT"). This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (e.g., NGL, crude oil, refined products and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs.

The following table summarizes our pipeline integrity costs, including those attributable to DOT regulations, for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Expensed	$ 17.8	$ 18.2	$ 26.8	$ 28.9
Capitalized	9.7	9.8	19.0	22.6
Total	$ 27.5	$ 28.0	$ 45.8	$ 51.5

We expect the cost of our pipeline integrity program, regardless of whether such costs are capitalized or expensed, to approximate $88.0 million for the remainder of 2014. The cost of our pipeline integrity program was $124.3 million for the year ended December 31, 2013.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2013 Form 10-K. The following estimates, in our opinion, are subjective in nature, require the exercise of professional judgment and involve complex analysis:

§ depreciation methods and estimated useful lives of property, plant and equipment;

§ measuring recoverability of long-lived assets and equity method investments;

§ amortization methods and estimated useful lives of qualifying intangible assets;

§ methods we employ to measure the fair value of goodwill; and

§ revenue recognition policies and the use of estimates for revenue and expenses.

When used to prepare our Unaudited Condensed Consolidated Financial Statements, the foregoing types of estimates are based on our current knowledge and understanding of the underlying facts and circumstances. Such estimates may be revised as a result of changes in the underlying facts and circumstances. Subsequent changes in these estimates may have a significant impact on our consolidated financial position, results of operations and cash flows.

Other Items

Use of Non-GAAP Financial Measures

***Gross operating margin*.** We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our executive management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. For additional information regarding gross operating margin, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report.

Our non-GAAP gross operating margin by business segment and in total is as follows for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
NGL Pipelines & Services	$ 680.9	$ 544.9	$ 1,460.9	$ 1,137.4
Onshore Natural Gas Pipelines & Services	203.0	197.7	423.4	388.5
Onshore Crude Oil Pipelines & Services	184.0	197.2	343.7	433.6
Offshore Pipelines & Services	33.6	39.7	72.9	80.2
Petrochemical & Refined Products Services	161.7	162.7	292.1	333.6
Total segment gross operating margin	$ 1,263.2	$ 1,142.2	$ 2,593.0	$ 2,373.3

The following table presents a reconciliation of non-GAAP total segment gross operating margin to GAAP operating income and further to income before income taxes for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Total segment gross operating margin	$ 1,263.2	$ 1,142.2	$ 2,593.0	$ 2,373.3
Adjustments to reconcile total segment gross operating margin to operating income:				
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(312.4)	(289.7)	(613.8)	(566.5)
Subtract impairment charges not reflected in gross operating margin	(3.7)	(27.1)	(12.5)	(38.1)
Add net gains or subtract net losses attributable to asset sales and insurance recoveries not reflected in gross operating margin	6.8	(5.7)	96.4	58.2
Subtract non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	(21.9)	--	(45.2)	--
Subtract general and administrative costs not reflected in gross operating margin	(47.7)	(45.5)	(100.9)	(95.0)
Operating income	884.3	774.2	1,917.0	1,731.9
Other expense, net	(227.8)	(200.5)	(449.0)	(396.5)
Income before income taxes	$ 656.5	$ 573.7	$ 1,468.0	$ 1,335.4

Distributable cash flow. Our management compares the distributable cash flow we generate to the cash distributions we expect to pay our partners. Using this metric, management computes our distribution coverage ratio. Distributable cash flow is an important non-GAAP financial measure for our limited partners since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flows at a level that can sustain or support an increase in our quarterly cash distributions. Distributable cash flow is also a quantitative standard used by the investment community with respect to publicly traded partnerships because the value of a partnership unit is, in part, measured by its yield, which is based on the amount of cash distributions a partnership can pay to a unitholder. The GAAP measure most directly comparable to distributable cash flow is net cash flows provided by operating activities.

The following table presents a reconciliation of non-GAAP distributable cash flow to GAAP net cash flows provided by operating activities for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Distributable cash flow	$ 953.8	$ 924.7	$ 2,040.8	$ 1,821.7
Adjustments to reconcile distributable cash flow to net cash flows provided by operating activities:				
Add sustaining capital expenditures reflected in distributable cash flow	76.9	74.8	155.2	132.1
Subtract cash proceeds from asset sales and insurance recoveries reflected in distributable cash flow	(16.9)	(68.7)	(113.2)	(199.2)
Add losses from monetization of interest rate derivative instruments accounted for as cash flow hedges	--	--	--	168.8
Net effect of changes in operating accounts not reflected in distributable cash flow	(541.1)	(401.2)	(198.6)	(409.2)
Other, net	(4.9)	1.4	(12.3)	16.7
Net cash flows provided by operating activities	$ 467.8	$ 531.0	$ 1,871.9	$ 1,530.9

Contractual Obligations

With the exception of routine fluctuations in the balances of our revolving credit facility and commercial paper notes, the issuance of Senior Notes JJ and KK in February 2014 and the scheduled repayment of maturing debt obligations, there have been no significant changes in our consolidated debt obligations since those reported in our 2013 Form 10-K. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report for information regarding our consolidated debt obligations.

During the second quarter of 2014, we entered into a long-term lease in connection with our plans to construct an ethane export terminal on the Houston Ship Channel. In addition, we entered into long-term railcar leases in connection with our other operations. On a combined basis, these agreements increased our estimated long-term operating lease obligations by approximately $34 million over the next five years and $144 million overall. Apart from these new agreements, there have been no other material changes in our operating lease commitments or other purchase obligations since those reported in our 2013 Form 10-K.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that have or are reasonably expected to have a material current or future effect on our financial position, results of operations and cash flows.

Related Party Transactions

For information regarding our related party transactions, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Insurance Matters

In February 2011, we experienced an NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. We collected $95.0 million and $8.8 million of nonrefundable cash insurance proceeds attributable to this incident during the six months ended June 30, 2014 and 2013, respectively. The payments we received during the first quarter of 2014 represent the final installments on this property damage claim.

Operating income for the six months ended June 30, 2014 and 2013 includes $95.0 million and $8.8 million, respectively, of gains related to these insurance recoveries. To the extent that nonrefundable cash insurance proceeds related to this incident were received, we recorded gains equal to such proceeds.

For additional information regarding insurance matters, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Recent Accounting Developments

For information regarding recent accounting developments, see Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Recent Litigation Developments

For information regarding recent litigation developments, see Part II, Item 1 of this quarterly report.

Item 3. *Quantitative and Qualitative Disclosures about Market Risk.*

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments such as futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

Our exposures to market risk have not changed materially since those reported under Part II, Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," included in our 2013 Form 10-K.

We assess the risk associated with each of our derivative instrument portfolios using a sensitivity analysis model. This approach measures the change in fair value of the derivative instrument portfolio based on a hypothetical 10% change in the underlying interest rates or quoted market prices on a particular day. In addition to these variables, the fair value of each portfolio is influenced by changes in the notional amounts of the instruments outstanding and the discount rates used to determine the present values. The sensitivity analysis approach does not reflect the impact that the same hypothetical price movement would have on the hedged exposures to which they relate. Therefore, the impact on the fair value of a derivative instrument resulting from a change in interest rates or quoted market prices (as applicable) would normally be offset by a corresponding gain or loss on the hedged debt instrument, inventory value or forecasted transaction assuming:

- the derivative instrument functions effectively as a hedge of the underlying risk;
- the derivative instrument is not closed out in advance of its expected term; and
- the hedged forecasted transaction occurs within the expected time period.

We routinely review the effectiveness of our derivative instrument portfolios in light of current market conditions. Accordingly, the nature and volume of our derivative instruments may change depending on the specific exposure being managed.

See Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for additional information regarding our derivative instruments and hedging activities.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our overall cost of capital associated with such borrowings. The composition of our derivative instrument portfolios may change from period-to-period depending on our hedging requirements.

With respect to the tabular data below, each portfolio's estimated fair value at a given date is based on a number of factors, including the number and types of derivatives outstanding at that date, the notional value of the swaps and associated interest rates.

Interest rate swaps

Interest rate swaps exchange the stated interest rate paid on a notional amount of existing debt for the fixed or floating interest rate stipulated in the derivative instrument. The following table summarizes our portfolio of interest rate swaps at June 30, 2014 (dollars in millions):

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes AA	10 fixed-to-floating swaps	$ 750.0	1/2011 to 2/2016	3.2% to 1.2%	Fair value hedge
Undesignated swaps	6 floating-to-fixed swaps	$ 600.0	5/2010 to 7/2014	0.2% to 2.0%	Mark-to-market

In July 2014, six undesignated floating-to-fixed swaps having an aggregate notional amount of $600.0 million, that were outstanding at June 30, 2014, expired.

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our interest rate swap portfolio at the dates indicated (dollars in millions):

		Interest Rate Swap Portfolio Aggregate Fair Value at		
Scenario	Resulting Classification	December 31, 2013	June 30, 2014	July 15, 2014
FV assuming no change in underlying interest rates	*Asset*	$ 24.8	$ 24.7	$ 26.9
FV assuming 10% increase in underlying interest rates	*Asset*	24.1	24.1	26.4
FV assuming 10% decrease in underlying interest rates	*Asset*	25.5	25.1	27.5

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, refined products and petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps, basis swaps and option contracts.

The following table summarizes our portfolio of commodity derivative instruments outstanding at June 30, 2014 (volume measures as noted):

	Volume (1)		Accounting
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	2.2	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	0.6	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	0.1	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	1.6	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities (Bcf)	3.3	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	6.2	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	7.6	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.6	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.0	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.2	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	3.3	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	5.0	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (4,5)	73.1	12.6	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	13.2	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is March 2015, August 2014 and October 2016, respectively.
(3) Forecasted sales of NGL volumes under natural gas processing exclude 0.6 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.
(4) Current volumes include 37.7 Bcf of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
(5) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

As of July 31, 2014, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging the fair value of commodity products held in inventory, (iii) hedging natural gas processing margins, and (iv) hedging octane enhancement margins.

The following information summarizes the primary objectives of these four hedging strategies:

§ The objective of our anticipated future commodity purchases and sales hedging program is to hedge the margins of certain transportation, storage and blending activities by locking in purchases and sales prices through the use of forward contracts and derivative instruments.

§ The objective of our inventory hedging program is to hedge the fair value of commodity products currently held in inventory by locking in the sales price of the inventory through the use of forward contracts and derivative instruments.

§ The objective of our natural gas processing hedging program is to hedge an amount of gross margin associated with these activities. We achieve this objective by executing forward fixed-price sales of a portion of our expected equity NGL production using forward contracts and commodity derivative instruments. For certain natural gas processing contracts, the hedging of expected equity NGL production also involves the purchase of natural gas for plant thermal reduction, which is hedged by executing forward fixed-price purchases using forward contracts and derivative instruments.

§ The objective of our octane enhancement hedging program is to hedge an amount of gross margin associated with these activities. We achieve this objective by executing forward fixed-price sales of a portion of our expected octane enhancement product volumes and forward fixed-price purchases of NGL feedstocks using forward contracts and derivative instruments.

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of commodity products. There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur during the periods originally forecasted. In accordance with derivatives accounting guidance, these instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of the underlying assets. Due to volatility in commodity prices, any non-cash, mark-to-market earnings variability cannot be predicted.

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our natural gas marketing portfolio at the dates indicated (dollars in millions):

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2013**	**June 30, 2014**	**July 15, 2014**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (1.3)	$ 2.0	$ 5.0
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(6.7)	(0.4)	2.5
FV assuming 10% decrease in underlying commodity prices	*Asset*	4.1	4.3	7.5

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our NGL marketing, refined products marketing and octane enhancement portfolios at the dates indicated (dollars in millions):

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2013**	**June 30, 2014**	**July 15, 2014**
FV assuming no change in underlying commodity prices	*Liability*	$ (20.7)	$ (17.5)	$ (4.7)
FV assuming 10% increase in underlying commodity prices	*Liability*	(69.8)	(47.3)	(34.2)
FV assuming 10% decrease in underlying commodity prices	*Asset*	28.5	12.4	24.8

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our crude oil marketing portfolio at the dates indicated (dollars in millions):

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2013**	**June 30, 2014**	**July 15, 2014**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ 8.2	$ (6.6)	$ 7.8
FV assuming 10% increase in underlying commodity prices	*Liability*	(9.8)	(25.2)	(7.6)
FV assuming 10% decrease in underlying commodity prices	*Asset*	26.1	12.0	23.1

Item 4. *Controls and Procedures*.

Disclosure Controls and Procedures

As of the end of the period covered by this quarterly report, our management carried out an evaluation, with the participation of our general partner's chief executive officer, Michael A. Creel (our principal executive officer), and chief financial officer, W. Randall Fowler (our principal financial officer), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on this evaluation, as of the end of the period covered by this quarterly report, Mr. Creel and Mr. Fowler concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our principal executive and financial officers, as appropriate to allow for timely decisions regarding required disclosures; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the second quarter of 2014, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The required certifications of Mr. Creel and Mr. Fowler under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 are included as exhibits to this quarterly report (see Exhibits 31 and 32 under Part II, Item 6 of this quarterly report).

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*.

As part of our normal business activities, we may be named as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We will vigorously defend the partnership in litigation matters.

For additional information regarding our litigation matters, see "Litigation" under Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report, which subsection is incorporated by reference into this Part II, Item 1.

Item 1A. *Risk Factors*.

Security holders and potential investors in our securities should carefully consider the risk factors set forth in our 2013 Form 10-K, in addition to other information in such annual report. The risk factors set forth in our 2013 Form 10-K are important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

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

The following table summarizes our repurchase activity during the six months ended June 30, 2014:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
February 2014 (1)	421,391	$ 65.69	--	--
May 2014 (2)	13,193	$ 73.25	--	--

(1) Of the 1,239,862 restricted common units that vested in February 2014 and converted to common units, 421,391 units were sold back to us by employees to cover related withholding tax requirements.

(2) Of the 36,900 restricted common units that vested in May 2014 and converted to common units, 13,193 units were sold back to us by employees to cover related withholding tax requirements.

Item 3. *Defaults Upon Senior Securities.*

None.

Item 4. *Mine Safety Disclosures.*

Not applicable.

Item 5. *Other Information.*

None.

Item 6. *Exhibits.*

Exhibit Number	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).

2.6	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed June 29, 2009).
2.7	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 29, 2009).
2.8	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise ETE LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2010).
2.9	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products GP, LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed September 7, 2010).
2.10	Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010).
2.11	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.6 to Form 8-K filed November 23, 2010).
3.3	Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated November 22, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K filed November 23, 2010).
3.4	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 11, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 16, 2011).
3.5	Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC) (incorporated by reference to Exhibit 3.3 to Form S-1/A Registration Statement, Reg. No. 333-124320, filed by Enterprise GP Holdings L.P. on July 22, 2005).
3.6	Certificate of Amendment to Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC), filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.5 to Form 8-K filed November 23, 2010).
3.7	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC dated effective as of September 7, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 8, 2011).
3.8	Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 8, 2007).
3.9	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.10	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit A to Exhibit 3.1 to Form 8-K filed August 16, 2011).
4.2	Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).

4.3	First Supplemental Indenture, dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed August 8, 2007).
4.6	Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 6, 2004).
4.7	Third Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 6, 2004).
4.8	Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 6, 2004).
4.9	Fifth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 3, 2005).
4.10	Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 3, 2005).
4.11	Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.12	Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed May 24, 2007).
4.13	Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.14	Eleventh Supplemental Indenture, dated as of September 4, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed September 5, 2007).
4.15	Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.16	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).

4.17	Fourteenth Supplemental Indenture, dated as of December 8, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.18	Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.19	Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.20	Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.21	Nineteenth Supplemental Indenture, dated as of May 20, 2010, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.22	Twentieth Supplemental Indenture, dated as of January 13, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.23	Twenty-First Supplemental Indenture, dated as of August 24, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.24	Twenty-Second Supplemental Indenture, dated as of February 15, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
4.25	Twenty-Third Supplemental Indenture, dated as of August 13, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 13, 2012).
4.26	Twenty-Fourth Supplemental Indenture, dated as of March 18, 2013, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.27	Twenty-Fifth Supplemental Indenture, dated as of February 12, 2014, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.28	Form of Global Note representing $350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.29	Form of Global Note representing $499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
4.30	Form of Global Note representing $500.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.31	Form of Global Note representing $150.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).

4.32	Form of Global Note representing $350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.33	Form of Global Note representing $250.0 million principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 4, 2005).
4.34	Form of Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
4.35	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.36	Form of Global Note representing $800.0 million principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007).
4.37	Form of Global Note representing $400.0 million principal amount of 5.65% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.38	Form of Global Note representing $700.0 million principal amount of 6.50% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.39	Form of Global Note representing $500.0 million principal amount of 9.75% Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.40	Form of Global Note representing $500.0 million principal amount of 5.25% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.41	Form of Global Note representing $600.0 million principal amount of 6.125% Senior Notes due 2039 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.42	Form of Global Note representing $182.6 million principal amount of 6.125% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 28, 2009).
4.43	Form of Global Note representing $237.6 million principal amount of 5.90% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 28, 2009).
4.44	Form of Global Note representing $349.7 million principal amount of 6.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed October 28, 2009).
4.45	Form of Global Note representing $399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit 4.7 to Form 8-K filed October 28, 2009).
4.46	Form of Global Note representing $285.8 million principal amount of 7.000% Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed October 28, 2009).
4.47	Form of Global Note representing $400.0 million principal amount of 3.70% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.48	Form of Global Note representing $1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.49	Form of Global Note representing $600.0 million principal amount of 6.45% Senior Notes due 2040 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.50	Form of Global Note representing $750.0 million principal amount of 3.20% Senior Notes due 2016 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).

4.51	Form of Global Note representing $750.0 million principal amount of 5.95% Senior Notes due 2041 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.52	Form of Global Note representing $650.0 million principal amount of 4.05% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
4.53	Form of Global Note representing $600.0 million principal amount of 5.70% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
4.54	Form of Global Note representing $750.0 million principal amount of 4.85% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 15, 2012).
4.55	Form of Global Note representing $650.0 million principal amount of 1.25% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 13, 2012).
4.56	Form of Global Note representing $1.1 billion principal amount of 4.45% Senior Notes due 2043 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 13, 2012).
4.57	Form of Global Note representing $1.25 billion principal amount of 3.35% Senior Notes due 2023 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed March 18, 2013).
4.58	Form of Global Note representing $1.0 billion principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed March 18, 2013).
4.59	Form of Global Note representing $850.0 million principal amount of 3.90% Senior Notes due 2024 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 12, 2014).
4.60	Form of Global Note representing $1.15 billion principal amount of 5.10% Senior Notes due 2045 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 12, 2014).
4.61	Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed May 24, 2007).
4.62	First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006).
4.63	Replacement Capital Covenant, dated October 27, 2009, among Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.9 to Form 8-K filed October 28, 2009).
4.64	Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.2 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.65	First Supplemental Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.3 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.66	Second Supplemental Indenture, dated June 27, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.6 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 14, 2002).

4.67	Third Supplemental Indenture, dated January 20, 2003, by and among TEPPCO Partners, L.P. as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.7 to the Form 10-K filed by TEPPCO Partners, L.P. on March 21, 2003).
4.68	Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of Jonah Gas Gathering Company (incorporated by reference to Exhibit 4.8 to the Form 10-Q filed by TEPPCO Partners, L.P. on November 7, 2006).
4.69	Fourth Supplemental Indenture, dated June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.70	Fifth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.11 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.71	Sixth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.12 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.72	Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.13 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.73	Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.74	Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed on March 1, 2010).
4.75	Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007).
4.76	First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007).
4.77	Replacement of Capital Covenant, dated May 18, 2007, executed by TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P. in favor of the covered debt holders described therein (incorporated by reference to Exhibit 99.1 to the Form 8-K of TEPPCO Partners, L.P. on May 18, 2007).

4.78	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.79	Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.80	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed on March 1, 2010).
12.1#	Computation of ratio of earnings to fixed charges for the six months ended June 30, 2014 and for each of the five years ended December 31, 2013, 2012, 2011, 2010 and 2009.
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the six months ended June 30, 2014.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the six months ended June 30, 2014.
32.1#	Sarbanes-Oxley Section 906 certification of Michael A. Creel for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the six months ended June 30, 2014.
32.2#	Sarbanes-Oxley Section 906 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the six months ended June 30, 2014.
101.CAL#	XBRL Calculation Linkbase Document
101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
101.LAB#	XBRL Labels Linkbase Document
101.PRE#	XBRL Presentation Linkbase Document
101.SCH#	XBRL Schema Document

*	With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file numbers for Enterprise Products Partners L.P., Enterprise GP Holdings L.P, TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC are 1-14323, 1-32610, 1-10403 and 1-13603, respectively.
#	Filed with this report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on August 11, 2014.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By: Enterprise Products Holdings LLC, as General Partner

By: /s/ Michael J. Knesek
Name: Michael J. Knesek
Title: Senior Vice President, Controller and Principal Accounting Officer of the General Partner

ENTERPRISE PRODUCTS PARTNERS L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in millions)

	For the Six Months Ended June 30, 2014	For the Year Ended December 31, 2013	2012	2011	2010	2009
Consolidated income	$ 1,453.2	$ 2,607.1	$ 2,428.0	$ 2,088.3	$ 1,383.7	$ 1,140.3
Add: Provision for (benefit from) taxes	14.8	57.5	(17.2)	27.2	26.1	25.3
Less: Equity in earnings from unconsolidated affiliates	(106.8)	(167.3)	(64.3)	(46.4)	(62.0)	(92.3)
Consolidated pre-tax income before equity in earnings from unconsolidated affiliates	1,361.2	2,497.3	2,346.5	2,069.1	1,347.8	1,073.3
Add: Fixed charges	501.2	964.7	920.3	879.5	813.4	760.6
Amortization of capitalized interest	12.1	22.8	20.3	17.5	16.8	15.3
Distributed income of equity investees	157.1	251.6	116.7	156.4	191.9	169.3
Subtotal	2,031.6	3,736.4	3,403.8	3,122.5	2,369.9	2,018.5
Less: Capitalized interest	(36.2)	(133.0)	(116.8)	(106.7)	(47.2)	(53.1)
Net income attributable to noncontrolling interests	(16.7)	(10.2)	(8.1)	(20.5)	(25.5)	(26.4)
Total earnings	$ 1,978.7	$ 3,593.2	$ 3,278.9	$ 2,995.3	$ 2,297.2	$ 1,939.0
Fixed charges:						
Interest expense	$ 449.8	$ 802.5	$ 771.8	$ 744.1	$ 741.9	$ 687.3
Capitalized interest	36.2	133.0	116.8	106.7	47.2	53.1
Interest portion of rental expense	15.2	29.2	31.7	28.7	24.3	20.2
Total	$ 501.2	$ 964.7	$ 920.3	$ 879.5	$ 813.4	$ 760.6
Ratio of earnings to fixed charges	3.9x	3.7x	3.6x	3.4x	2.8x	2.6x

These computations take into account our consolidated operations and the distributed income from our equity method investees. For purposes of these calculations, "earnings" is the amount resulting from adding and subtracting the following items:

Add the following, as applicable:

- consolidated pre-tax income from continuing operations before adjustment for income or loss from equity investees;
- fixed charges;
- amortization of capitalized interest;
- distributed income of equity investees; and
- our share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges.

From the subtotal of the added items, subtract the following, as applicable:

- interest capitalized;
- preference security dividend requirements of consolidated subsidiaries; and
- the noncontrolling interests in pre-tax income of subsidiaries that have not incurred fixed charges.

The term "fixed charges" means the sum of the following: interest expensed and capitalized; amortized premiums, discounts and capitalized expenses related to indebtedness; an estimate of the interest within rental expense; and preference security dividend requirements of consolidated subsidiaries.

EXHIBIT 31.1

SARBANES-OXLEY SECTION 302 CERTIFICATION

I, Michael A. Creel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 11, 2014

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Chief Executive Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

EXHIBIT 31.2

SARBANES-OXLEY SECTION 302 CERTIFICATION

I, W. Randall Fowler, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 11, 2014

/s/ W. Randall Fowler

Name:	W. Randall Fowler
Title:	Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF MICHAEL A. CREEL, CHIEF EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS HOLDINGS LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this quarterly report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-Q for the quarterly period ended June 30, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Executive Officer of Enterprise Products Holdings LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

Date: August 11, 2014

/s/ Michael A. Creel

Name:	Michael A. Creel
Title:	Chief Executive Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF W. RANDALL FOWLER, CHIEF FINANCIAL OFFICER OF ENTERPRISE PRODUCTS HOLDINGS LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this quarterly report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-Q for the quarterly period ended June 30, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

Date: August 11, 2014

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.