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 September 30, 2014

OR

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

For the transition period from ___ to ___.

Commission file number: 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 ☐

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 ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

Yes ☐ No ☐

There were 1,935,026,941 common units of Enterprise Products Partners L.P. outstanding at the close of business on October 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)

	September 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,061.6	$ 56.9
Restricted cash	6.6	65.6
Accounts receivable – trade, net of allowance for doubtful accounts of $14.8 at September 30, 2014 and $7.5 at December 31, 2013	5,320.8	5,475.5
Accounts receivable – related parties	2.6	6.8
Inventories	1,589.5	1,093.1
Prepaid and other current assets	384.4	325.5
Total current assets	8,365.5	7,023.4
Property, plant and equipment, net	27,963.3	26,946.6
Investments in unconsolidated affiliates	2,938.3	2,437.1
Intangible assets, net of accumulated amortization of $1,208.4 at September 30, 2014 and $1,150.0 at December 31, 2013	1,391.1	1,462.2
Goodwill (see Note 8)	2,079.9	2,080.0
Other assets	167.4	189.4
Total assets	$ 42,905.5	$ 40,138.7
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 9)	$ 1,939.9	$ 1,125.0
Accounts payable – trade	728.0	723.7
Accounts payable – related parties	122.6	150.5
Accrued product payables	5,564.6	5,608.7
Accrued interest	172.5	304.3
Other current liabilities	444.2	326.5
Total current liabilities	8,971.8	8,238.7
Long-term debt (see Note 9)	17,706.5	16,226.5
Deferred tax liabilities	63.2	60.8
Other long-term liabilities	182.1	172.3
Commitments and contingencies (see Note 14)		
Equity: (see Note 10)		
Partners' equity:		
Limited partners:		
Common units (1,880,223,189 units outstanding at September 30, 2014 and 1,871,370,016 units outstanding at December 31, 2013)	16,063.6	15,573.8
Accumulated other comprehensive loss	(306.1)	(359.0)
Total partners' equity	15,757.5	15,214.8
Noncontrolling interests	224.4	225.6
Total equity	15,981.9	15,440.4
Total liabilities and equity	$ 42,905.5	$ 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 September 30, 2014	For the Three Months Ended September 30, 2013	For the Nine Months Ended September 30, 2014	For the Nine Months Ended September 30, 2013
Revenues:				
Third parties	$ 12,319.2	$ 12,085.6	$ 37,697.1	$ 34,605.4
Related parties	11.0	7.7	63.8	20.3
Total revenues (see Note 11)	12,330.2	12,093.3	37,760.9	34,625.7
Costs and expenses:				
Operating costs and expenses:				
Third parties	11,198.1	11,055.3	34,198.9	31,404.5
Related parties	216.7	218.2	735.5	656.6
Total operating costs and expenses	11,414.8	11,273.5	34,934.4	32,061.1
General and administrative costs:				
Third parties	18.1	17.4	60.0	54.6
Related parties	31.9	26.5	90.9	84.3
Total general and administrative costs	50.0	43.9	150.9	138.9
Total costs and expenses (see Note 11)	11,464.8	11,317.4	35,085.3	32,200.0
Equity in income of unconsolidated affiliates	72.3	44.0	179.1	126.1
Operating income	937.7	819.9	2,854.7	2,551.8
Other income (expense):				
Interest expense	(229.8)	(208.3)	(679.6)	(604.4)
Interest income	0.3	0.2	1.1	0.7
Other, net	(1.3)	0.4	(1.3)	(0.5)
Total other expense, net	(230.8)	(207.7)	(679.8)	(604.2)
Income before income taxes	706.9	612.2	2,174.9	1,947.6
Provision for income taxes	(7.7)	(19.4)	(22.5)	(46.2)
Net income	699.2	592.8	2,152.4	1,901.4
Net income attributable to noncontrolling interests (see Note 10)	(8.1)	(0.8)	(24.8)	(3.4)
Net income attributable to limited partners	$ 691.1	$ 592.0	$ 2,127.6	$ 1,898.0
Earnings per unit: (see Note 13)				
Basic earnings per unit	$ 0.38	$ 0.33	$ 1.16	$ 1.07
Diluted earnings per unit	$ 0.37	$ 0.32	$ 1.13	$ 1.03

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	**2013**	**2014**	**2013**
Net income	$ 699.2	$ 592.8	$ 2,152.4	$ 1,901.4
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instruments:				
Changes in fair value of cash flow hedges	58.1	(8.6)	16.1	(22.1)
Reclassification of losses (gains) to net income	(18.0)	14.6	12.9	14.7
Interest rate derivative instruments:				
Changes in fair value of cash flow hedges	--	--	--	6.7
Reclassification of losses to net income	8.0	7.7	23.9	21.4
Total cash flow hedges	48.1	13.7	52.9	20.7
Other	--	--	--	0.4
Total other comprehensive income	48.1	13.7	52.9	21.1
Comprehensive income	747.3	606.5	2,205.3	1,922.5
Comprehensive income attributable to noncontrolling interests	(8.1)	(0.8)	(24.8)	(3.4)
Comprehensive income attributable to limited partners	$ 739.2	$ 605.7	$ 2,180.5	$ 1,919.1

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 Nine Months Ended September 30, 2014	2013
Operating activities:		
Net income	$ 2,152.4	$ 1,901.4
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	992.4	902.3
Non-cash asset impairment charges (see Note 4)	18.2	53.3
Equity in income of unconsolidated affiliates	(179.1)	(126.1)
Distributions received from unconsolidated affiliates	260.7	187.6
Net gains attributable to asset sales and insurance recoveries (see Note 16)	(99.0)	(68.4)
Deferred income tax expense	2.6	32.1
Changes in fair market value of derivative instruments	(3.8)	(5.3)
Net effect of changes in operating accounts (see Note 16)	(435.8)	(513.9)
Other operating activities	(4.2)	3.2
Net cash flows provided by operating activities	2,704.4	2,366.2
Investing activities:		
Capital expenditures	(1,879.5)	(2,413.2)
Contributions in aid of construction costs	20.0	19.9
Decrease (increase) in restricted cash	59.0	(31.6)
Investments in unconsolidated affiliates	(583.3)	(768.4)
Proceeds from asset sales and insurance recoveries (see Note 16)	121.5	256.3
Other investing activities	(5.8)	(0.5)
Cash used in investing activities	(2,268.1)	(2,937.5)
Financing activities:		
Borrowings under debt agreements	7,167.5	10,139.2
Repayments of debt	(4,856.3)	(8,791.6)
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)	(1,948.2)	(1,778.3)
Cash payments made in connection with distribution equivalent rights	(2.4)	--
Cash distributions paid to noncontrolling interests	(29.4)	(6.4)
Cash contributions from noncontrolling interests (see Note 10)	4.0	104.2
Net cash proceeds from the issuance of common units	304.9	1,134.7
Other financing activities	(53.6)	(44.5)
Cash provided by financing activities	568.4	564.8
Net change in cash and cash equivalents	1,004.7	(6.5)
Cash and cash equivalents, January 1	56.9	16.1
Cash and cash equivalents, September 30	$ 1,061.6	$ 9.6

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	2,127.6	--	24.8	2,152.4
Cash distributions paid to limited partners	(1,948.2)	--	--	(1,948.2)
Cash payments made in connection with distribution equivalent rights	(2.4)	--	--	(2.4)
Cash distributions paid to noncontrolling interests	--	--	(29.4)	(29.4)
Cash contributions from noncontrolling interests	--	--	4.0	4.0
Net cash proceeds from the issuance of common units	304.9	--	--	304.9
Amortization of fair value of equity-based awards	61.6	--	--	61.6
Cash flow hedges	--	52.9	--	52.9
Other	(53.7)	--	(0.6)	(54.3)
Balance, September 30, 2014	$ 16,063.6	$ (306.1)	$ 224.4	$ 15,981.9

	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	1,898.0	--	3.4	1,901.4
Cash distributions paid to limited partners	(1,778.3)	--	--	(1,778.3)
Cash distributions paid to noncontrolling interests	--	--	(6.4)	(6.4)
Cash contributions from noncontrolling interests	--	--	104.2	104.2
Net cash proceeds from the issuance of common units	1,134.7	--	--	1,134.7
Amortization of fair value of equity-based awards	53.5	--	--	53.5
Cash flow hedges	--	20.7	--	20.7
Other	(44.6)	0.4	0.6	(43.6)
Balance, September 30, 2013	$ 14,821.4	$ (349.3)	$ 210.1	$ 14,682.2

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 September 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 currently 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, storage and terminals, and related 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 52,000 miles of onshore and offshore pipelines; 220 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.

On October 1, 2014, we announced our acquisition of the general partner and certain limited partner interests of Oiltanking Partners, L.P. See Note 18 for information regarding this subsequent event.

Note 2. General Accounting Matters

Our results of operations for the three and nine months ended September 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 10 for information regarding a two-for-one common unit split completed on August 21, 2014. All per unit amounts and number of units outstanding in these Unaudited Condensed Consolidated Financial Statements and Notes thereto are presented on a post-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 September 30, 2014 and December 31, 2013, our restricted cash amounts were $6.6 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Equity-classified awards:				
Restricted common unit awards	$ 8.7	$ 17.8	$ 29.3	$ 52.7
Unit option awards	--	0.1	--	0.7
Phantom unit awards	12.9	--	32.3	--
Liability-classified awards	0.1	0.1	0.4	0.4
Total	$ 21.7	$ 18.0	$ 62.0	$ 53.8

The fair value of equity-classified awards is amortized into 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 September 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 14,000,000 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 25,000,000 at September 30, 2014. This amount will automatically increase under the terms of the 2008 Plan by 5,000,000 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 70,000,000 common units. After giving effect to awards granted under the 1998 Plan and 2008 Plan through September 30, 2014, a total of 2,704,337 and 12,782,238 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	7,221,214	$ 25.83
Vested	(2,586,398)	$ 23.92
Forfeited	(267,200)	$ 26.36
Restricted common units at September 30, 2014	4,367,616	$ 26.93

(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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Cash distributions paid to restricted common unitholders	$ 1.6	$ 2.6	$ 5.7	$ 8.2
Total intrinsic value of restricted common unit awards that vested during period	$ 1.3	$ 1.0	$ 85.4	$ 107.4

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $37.8 million at September 30, 2014, of which our allocated share of the cost is currently estimated to be $33.6 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 1.6 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 (2)	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Unit option awards at December 31, 2013	4,050,000	$ 13.24	1.3	$ 57.0
Exercised	(2,720,000)	$ 11.83		
Forfeited	(60,000)	$ 16.14		
Unit option awards at September 30, 2014	1,270,000	$ 16.14	1.3	$ 30.7

(1) Aggregate intrinsic value reflects fully vested unit option awards at the dates indicated.

(2) None of the unit option awards outstanding at September 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Total intrinsic value of unit option awards exercised during period	$ --	$ --	$ 57.5	$ 19.8
Cash received from EPCO in connection with the exercise of unit option awards	--	--	33.4	11.5
Unit option award-related cash reimbursements to EPCO	--	--	57.5	19.8

As of September 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 September 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)	3,522,990	$ 33.12
Vested	(34,800)	$ 33.04
Forfeited	(92,800)	$ 33.04
Phantom unit awards at September 30, 2014	3,395,390	$ 33.12

(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 $116.7 million based on a grant date market price of our common units ranging from $33.04 to $37.59 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Cash payments made in connection with DERs	$ 1.2	$ --	$ 2.4	$ --
Total intrinsic value of phantom unit awards that vested during period	$ 0.1	$ --	$ 1.3	$ --

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was $72.2 million at September 30, 2014, of which our allocated share of the cost is currently estimated to be $66.1 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 2.2 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 September 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

As a result of market conditions in early October 2014, we elected to terminate all of our outstanding interest rate swaps. We terminated 10 fixed-to-floating swaps that were outstanding at September 30, 2014 having an aggregate notional value of $750 million, which resulted in cash gains totaling $17.6 million. In addition, we terminated 16 fixed-to-floating swaps having a notional value of $800 million entered into in connection with the issuance of Senior Notes LL in October 2014 (see Note 18). The early termination of these 16 swaps resulted in cash gains totaling $10.0 million. Since both groups of swaps were accounted for as fair value hedges, the aggregate $27.6 million of gains will be carried as a component of long-term debt and amortized into earnings (as a decrease in interest expense) using the effective interest method over the remaining life of the associated debt obligations. The $17.6 million gain will be amortized through January 2016 and the $10.0 million gain will be amortized through October 2019.

In July 2014, six undesignated floating-to-fixed swaps having an aggregate notional amount of $600.0 million 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 terminated 16 forward starting swaps having an aggregate notional amount of $1.0 billion, which resulted in cash losses totaling $168.8 million. As cash flow hedges, losses on these derivative instruments are a component of accumulated other comprehensive loss and are being amortized into earnings (as an increase in interest expense) over the remaining life of the associated debt obligations using the effective interest method. The $168.8 million loss will be amortized through March 2023.

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 September 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)	1.1	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	0.3	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	0.3	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	0.2	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted sales of natural gas (Bcf)	1.7	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	5.1	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	5.2	0.1	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	8.8	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.7	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.3	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	5.0	0.5	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	7.0	0.5	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (4,5)	63.5	15.3	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	6.7	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 December 2015, October 2015 and March 2018, respectively.
(3) Forecasted sales of NGL volumes under natural gas processing exclude 0.3 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.
(4) Current and long-term volumes include 28.9 Bcf and 0.9 Bcf, respectively, 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 September 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.

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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			
	September 30, 2014		December 31, 2013		September 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	$ 15.9	Other current assets	$ 20.2	Other current liabilities	$ --	Other current liabilities	$ --
Interest rate derivatives	Other assets	3.5	Other assets	12.4	Other liabilities	--	Other liabilities	--
Total interest rate derivatives		19.4		32.6		--		--
Commodity derivatives	Other current assets	38.1	Other current assets	30.9	Other current liabilities	19.5	Other current liabilities	46.5
Commodity derivatives	Other assets	1.2	Other assets	--	Other liabilities	1.4	Other liabilities	0.3
Total commodity derivatives		39.3		30.9		20.9		46.8
Total derivatives designated as hedging instruments		$ 58.7		$ 63.5		$ 20.9		$ 46.8
Derivatives not designated as hedging instruments								
Interest rate derivatives	Other current assets	$ --	Other current assets	$ --	Other current liabilities	$ --	Other current liabilities	$ 7.8
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	--	Other liabilities	--
Total interest rate derivatives		--		--		--		7.8
Commodity derivatives	Other current assets	1.4	Other current assets	7.6	Other current liabilities	0.8	Other current liabilities	5.5
Commodity derivatives	Other assets	1.0	Other assets	2.8	Other liabilities	0.3	Other liabilities	2.8
Total commodity derivatives		2.4		10.4		1.1		8.3
Total derivatives not designated as hedging instruments		$ 2.4		$ 10.4		$ 1.1		$ 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 September 30, 2014:						
Interest rate derivatives	$ 19.4	$ --	$ 19.4	$ --	$ --	$ 19.4
Commodity derivatives	41.7	--	41.7	(24.8)	(16.9)	--
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

	Offsetting of Financial Liabilities and Derivative Liabilities					
				Gross Amounts Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Financial Instruments	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)		(v) = (iii) + (iv)
As of September 30, 2014:						
Interest rate derivatives	$ --	$ --	$ --	$ --	$ --	$ --
Commodity derivatives	22.0	--	22.0	(24.8)	7.8	5.0
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 September 30,		For the Nine Months Ended September 30,	
		2014	2013	2014	2013
Interest rate derivatives	Interest expense	$ (4.1)	$ (0.5)	$ (9.5)	$ (10.6)
Commodity derivatives	Revenue	(0.3)	(3.1)	0.6	3.1
Total		$ (4.4)	$ (3.6)	$ (8.9)	$ (7.5)

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2014	2013	2014	2013
Interest rate derivatives	Interest expense	$ 3.9	$ 0.4	$ 9.3	$ 10.3
Commodity derivatives	Revenue	1.0	(0.4)	(1.4)	(12.0)
Total		$ 4.9	$ --	$ 7.9	$ (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.

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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Interest rate derivatives	$ --	$ --	$ --	$ 6.7
Commodity derivatives – Revenue (1)	58.8	(8.6)	15.2	(22.1)
Commodity derivatives – Operating costs and expenses (1)	(0.7)	--	0.9	--
Total	$ 58.1	$ (8.6)	$ 16.1	$ (15.4)

(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 September 30,		For the Nine Months Ended September 30,	
		2014	2013	2014	2013
Interest rate derivatives	Interest expense	$ (8.0)	$ (7.7)	$ (23.9)	$ (21.4)
Commodity derivatives	Revenue	17.8	(14.6)	(14.5)	(15.1)
Commodity derivatives	Operating costs and expenses	0.2	--	1.6	0.4
Total		$ 10.0	$ (22.3)	$ (36.8)	$ (36.1)

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

Over the next twelve months, we expect to reclassify $34.8 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 $14.5 million of net gains attributable to commodity derivative instruments from accumulated other comprehensive income to earnings, $14.3 million as an increase in revenue and $0.2 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 September 30,		For the Nine Months Ended September 30,	
		2014	2013	2014	2013
Interest rate derivatives	Interest expense	$ --	$ (0.5)	$ (0.1)	$ (0.6)
Commodity derivatives	Revenue	0.8	8.1	(26.8)	17.0
Total		$ 0.8	$ 7.6	$ (26.9)	$ 16.4

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 September 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.

	September 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)	Total
Financial assets:				
Interest rate derivatives	$ --	$ 19.4	$ --	$ 19.4
Commodity derivatives	14.4	24.4	2.9	41.7
Total	$ 14.4	$ 43.8	$ 2.9	$ 61.1
Financial liabilities:				
Interest rate derivatives	$ --	$ --	$ --	$ --
Commodity derivatives	8.2	10.2	3.6	22.0
Total	$ 8.2	$ 10.2	$ 3.6	$ 22.0

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	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)	Total
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 Nine Months Ended September 30, 2014	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		2.6	(0.2)
Total gains (losses) included in:			
Net income (1)	Revenue	(0.9)	1.1
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	(2.5)	(0.9)
Settlements	Revenue	0.1	0.1
Financial asset (liability) balance, net, September 30 (2)		$ (0.7)	$ 0.1

(1) There were $0.8 million and $1.3 million of unrealized losses included in these amounts for the three and nine months ended September 30, 2014, respectively. There were unrealized gains of $1.1 million and $2.4 million included in these amounts for the three and nine months ended September 30, 2013, respectively.

(2) There were no transfers into or out of Level 3 during the three or nine months ended September 30, 2014 and 2013.

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

	Fair Value Financial Assets	Fair Value Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Crude oil	$ 2.6	$ 0.9	Discounted cash flow	Forward commodity prices	$70.32-$91.82/barrel
Commodity derivatives – Propane	--	0.1	Discounted cash flow	Forward commodity prices	$1.02-$1.05/gallon
Commodity derivatives – Natural gasoline	0.1	2.5	Discounted cash flow	Forward commodity prices	$1.84-$1.94/gallon
Commodity derivatives – Natural gas	0.2	0.1	Discounted cash flow	Forward commodity prices	$3.72-$4.54/MMBtu
Total	$ 2.9	$ 3.6			

We believe forward commodity prices are the most significant unobservable inputs in determining our Level 3 recurring fair value measurements at September 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
NGL Pipelines & Services	$ 1.2	$ 0.3	$ 6.6	$ 10.0
Onshore Natural Gas Pipelines & Services	0.4	--	0.7	--
Onshore Crude Oil Pipelines & Services	0.4	--	2.2	16.6
Offshore Pipelines & Services	--	13.2	--	13.2
Petrochemical & Refined Products Services	3.7	1.7	8.7	13.5
Total	$ 5.7	$ 15.2	$ 18.2	$ 53.3

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 nine months ended September 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 nine months ended September 30, 2014:

		Fair Value Measurements Using			
	Carrying Value at September 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	$ --	$ --	$ --	$ --	$ 11.7
Impairment of long-lived assets to be disposed of by sale	1.1	--	--	1.1	6.5
Total					$ 18.2

During the nine months ended September 30, 2013, we recorded $53.3 million of non-cash asset impairment charges. These charges primarily represent the abandonment of crude oil and natural gas pipeline segments in Texas, Oklahoma and the Gulf of Mexico, certain refined products terminal assets in Texas, and an NGL storage cavern in Arizona. The following table summarizes our non-recurring fair value measurements for the nine months ended September 30, 2013:

		Fair Value Measurements Using			
	Carrying Value at September 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	$ --	$ --	$ --	$ --	$ 43.3
Impairment of long-lived assets held and used	6.1	--	--	6.1	4.2
Impairment of long-lived assets to be disposed of by sale	11.7	11.7	--	--	5.8
Total					$ 53.3

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 $20.1 billion and $17.93 billion at September 30, 2014 and December 31, 2013, respectively. The aggregate carrying value of these debt obligations was $18.38 billion and $16.88 billion at September 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:

	September 30, 2014	December 31, 2013
NGLs	$ 973.4	$ 593.8
Petrochemicals and refined products	338.7	395.1
Crude oil	238.8	42.6
Natural gas	38.6	61.6
Total	$ 1,589.5	$ 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Cost of sales (1)	$ 10,455.1	$ 10,371.3	$ 32,213.1	$ 29,522.1
Lower of cost or market adjustments	6.7	4.5	14.6	14.9

(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	September 30, 2014	December 31, 2013
Plants, pipelines and facilities (1)	3-45 (6)	$ 30,096.7	$ 27,540.4
Underground and other storage facilities (2)	5-40 (7)	2,164.9	2,101.8
Platforms and facilities (3)	20-31	659.7	659.6
Transportation equipment (4)	3-10	142.0	138.9
Marine vessels (5)	15-30	782.3	744.8
Land		185.0	176.6
Construction in progress		1,805.7	2,655.5
Total		35,836.3	34,017.6
Less accumulated depreciation		7,873.0	7,071.0
Property, plant and equipment, net		$ 27,963.3	$ 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Depreciation expense (1)	$ 283.2	$ 253.4	$ 822.1	$ 749.6
Capitalized interest (2)	17.2	27.8	53.4	95.1

(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 nine months ended September 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 nine months ended September 30, 2013 includes a $6.7 million gain from the sale of these assets.

Asset Retirement Obligations

Property, plant and equipment at September 30, 2014 and December 31, 2013 includes $31.8 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 nine months ended September 30, 2014:

ARO liability balance, December 31, 2013	$ 90.2
Liabilities incurred	0.1
Liabilities settled	(2.3)
Revisions in estimated cash flows	2.7
Accretion expense	4.5
ARO liability balance, September 30, 2014	$ 95.2

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

Remainder of 2014	2015	2016	2017	2018
$ 1.6	$ 6.3	$ 6.5	$ 7.0	$ 7.5

Certain of our unconsolidated affiliates have AROs recorded at September 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 September 30, 2014	September 30, 2014	December 31, 2013
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 26.9	$ 27.6
K/D/S Promix, L.L.C.	50%	46.1	45.4
Baton Rouge Fractionators LLC	32.2%	19.1	19.5
Skelly-Belvieu Pipeline Company, L.L.C.	50%	39.7	40.8
Texas Express Pipeline LLC	35%	348.4	339.9
Texas Express Gathering LLC	45%	37.8	37.8
Front Range Pipeline LLC	33.3%	167.8	134.5
Onshore Natural Gas Pipelines & Services:			
White River Hub, LLC	50%	23.5	24.2
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC	50%	1,372.2	940.7
Eagle Ford Pipeline LLC	50%	279.5	224.5
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	34.3	41.7
Cameron Highway Oil Pipeline Company	50%	204.2	207.7
Deepwater Gateway, L.L.C.	50%	81.1	84.5
Neptune Pipeline Company, L.L.C.	25.7%	35.4	38.7
Southeast Keathley Canyon Pipeline Company L.L.C.	50%	147.4	159.2
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	6.7	7.6
Centennial Pipeline LLC ("Centennial")	50%	65.6	60.1
Other	Various	2.6	2.7
Total		$ 2,938.3	$ 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
NGL Pipelines & Services	$ 11.7	$ 4.1	$ 19.2	$ 11.8
Onshore Natural Gas Pipelines & Services	0.9	1.0	2.7	2.9
Onshore Crude Oil Pipelines & Services	46.8	34.3	131.7	101.0
Offshore Pipelines & Services	17.1	9.8	35.8	24.9
Petrochemical & Refined Products Services	(4.2)	(5.2)	(10.3)	(14.5)
Total	$ 72.3	$ 44.0	$ 179.1	$ 126.1

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

	September 30, 2014	December 31, 2013
NGL Pipelines & Services	$ 26.8	$ 27.7
Onshore Crude Oil Pipelines & Services	17.3	17.8
Offshore Pipelines & Services	9.2	10.0
Petrochemical & Refined Products Services	2.5	2.6
Total	$ 55.8	$ 58.1

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
NGL Pipelines & Services	$ 0.2	$ 0.3	$ 0.9	$ 0.9
Onshore Crude Oil Pipelines & Services	0.2	0.1	0.5	0.5
Offshore Pipelines & Services	0.3	0.3	0.8	1.0
Petrochemical & Refined Products Services	--	0.1	0.1	0.1
Total	$ 0.7	$ 0.8	$ 2.3	$ 2.5

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 September 30, 2014.

Note 8. Intangible Assets and Goodwill

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

	September 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	$ (179.0)	$ 161.8	$ 340.8	$ (165.7)	$ 175.1
Contract-based intangibles	277.9	(175.1)	102.8	281.3	(171.2)	110.1
Segment total	618.7	(354.1)	264.6	622.1	(336.9)	285.2
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,163.6	(302.3)	861.3	1,163.6	(281.2)	882.4
Contract-based intangibles	466.0	(343.7)	122.3	466.1	(330.7)	135.4
Segment total	1,629.6	(646.0)	983.6	1,629.7	(611.9)	1,017.8
Onshore Crude Oil Pipelines & Services:						
Customer relationship intangibles	9.6	(6.1)	3.5	10.7	(6.3)	4.4
Contract-based intangibles	0.4	(0.3)	0.1	0.4	(0.3)	0.1
Segment total	10.0	(6.4)	3.6	11.1	(6.6)	4.5
Offshore Pipelines & Services:						
Customer relationship intangibles	195.8	(152.6)	43.2	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	(153.1)	43.9	205.1	(150.4)	54.7
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.3	(42.1)	62.2	104.3	(38.2)	66.1
Contract-based intangibles	39.9	(6.7)	33.2	39.9	(6.0)	33.9
Segment total	144.2	(48.8)	95.4	144.2	(44.2)	100.0
Total all segments	$ 2,599.5	$ (1,208.4)	$ 1,391.1	$ 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
NGL Pipelines & Services	$ 8.1	$ 8.6	$ 25.4	$ 27.7
Onshore Natural Gas Pipelines & Services	11.1	13.3	34.2	38.0
Onshore Crude Oil Pipelines & Services	0.3	0.3	0.9	1.0
Offshore Pipelines & Services	2.5	2.9	7.6	8.8
Petrochemical & Refined Products Services	1.5	1.5	4.6	4.7
Total	$ 23.5	$ 26.6	$ 72.7	$ 80.2

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
$ 22.2	$ 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 nine months ended September 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 September 30, 2014 (1)	$ 861.2	$ 296.3	$ 305.1	$ 82.0	$ 535.3	$ 2,079.9

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

In January 2014, our Appalachia-to-Texas Express ("ATEX") ethane pipeline commenced operations. In addition to the 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:

	September 30, 2014	December 31, 2013
EPO senior debt obligations:		
Commercial Paper Notes, fixed-rates (1)	$ 1,290.0	$ 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
$1.5 Billion 364-Day Credit Agreement, variable-rate, due September 2015	--	--
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	18,140.0	15,825.0
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066 (2)	550.0	550.0
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 (3)	285.8	285.8
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068 (4)	682.7	682.7
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2
Total principal amount of senior and junior debt obligations	19,672.7	17,357.7
Other, non-principal amounts	(26.3)	(6.2)
Less current maturities of debt (5)	(1,939.9)	(1,125.0)
Total long-term debt	$ 17,706.5	$ 16,226.5

(1) Principal amounts outstanding at September 30, 2014 have fixed rates ranging from 0.22% and 0.29% and are due in October 2014.

(2) Fixed rate of 8.375% through August 1, 2016; thereafter, variable rate based on 3-month LIBOR plus 3.7075%.

(3) Fixed rate of 7.0% through September 1, 2017; thereafter, variable rate based on 3-month LIBOR plus 2.7775%.

(4) 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%.

(5) We expect to refinance the current maturities of our debt obligations at or prior to their maturity. Long-term and current maturities of debt reflect the classification of such obligations at September 30, 2014 after taking into consideration the long-term refinancing of Senior Notes G and $650 million of Commercial Paper Notes using proceeds from the issuance of senior notes in October 2014 (see Note 18).

The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at September 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
Commercial Paper	$ 1,290.0	$ 1,290.0	$ --	$ --	$ --	$ --	$ --
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	$ 19,672.7	$ 1,940.0	$ 1,300.0	$ 750.0	$ 800.0	$ 350.0	$ 14,532.7

In October 2014, EPO issued $2.75 billion in aggregate principal amount of additional senior notes (see Note 18). Net proceeds from the issuance of these senior notes of $2.73 billion were used as follows: (i) to repay debt principal amounts outstanding under EPO's 364-Day Credit Agreement and commercial paper program (both of which were used to partially fund the cash consideration paid in Step 1 of the Oiltanking acquisition (see Note 18)), (ii) to repay $650.0 million in principal amount of Senior Notes G that matured in October 2014, and (iii) for general company purposes.

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 due June 2014 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.

New 364-Day Credit Agreement due September 2015

On September 30, 2014, EPO entered into a new 364-Day Revolving Credit Agreement (the "364-Day Credit Agreement"). Under the terms of the 364-Day Credit Agreement, EPO may borrow up to $1.5 billion (which may be increased by up to $200 million to $1.7 billion at EPO's election) at a variable interest rate for a term of 364 days, subject to the terms and conditions set forth therein. On October 1, 2014, we borrowed $1.5 billion under the 364-Day Credit Agreement to partially fund the cash consideration paid under Step 1 of the Oiltanking acquisition (see Note 18). This amount was subsequently repaid using proceeds from the issuance of senior notes in October 2014 (see Note 18).

To the extent that principal amounts are outstanding, EPO's obligations under the 364-Day Credit Agreement are not secured by any collateral; however, they are guaranteed by Enterprise Products Partners L.P. Any amounts borrowed under the 364-Day Credit Agreement mature on September 29, 2015, although EPO may, between 15 and 60 days prior to the maturity date, elect to have the entire principal balance then outstanding continued as non-revolving term loans for a period of one additional year, payable on September 29, 2016.

The 364-Day Credit Agreement contains customary representations, warranties, covenants (affirmative and negative) and events of default, the occurrence of which would permit the lenders to accelerate the maturity date of any amounts borrowed under the 364-Day Credit Agreement. The 364-Day Credit Agreement also restricts EPO's ability to pay cash distributions to its parent, Enterprise Products Partners L.P., if a default or an event of default (as defined in the 364-Day Credit Agreement) has occurred and is continuing at the time such distribution is scheduled to be paid or would result therefrom.

Letters of Credit

At September 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 September 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 nine months ended September 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	1,864,148,802	7,221,214	1,871,370,016
Common units issued in connection with at-the-market program	1,590,334	--	1,590,334
Common units issued in connection with DRIP and EUPP	7,355,904	--	7,355,904
Common units issued in connection with the vesting and exercise of unit options	1,014,108	--	1,014,108
Common units issued in connection with the vesting of phantom unit awards	20,842	--	20,842
Common units issued in connection with the vesting of restricted common unit awards	2,586,398	(2,586,398)	--
Forfeiture of restricted common unit awards	--	(267,200)	(267,200)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(878,017)	--	(878,017)
Other	17,202	--	17,202
Number of units outstanding at September 30, 2014	1,875,855,573	4,367,616	1,880,223,189

On October 1, 2014, in order to fund the equity consideration paid in Step 1 of the Oiltanking acquisition, we issued 54,807,352 common units to Oiltanking Holding Americas, Inc. Pursuant to a Registration Rights Agreement, we granted the seller registration rights with respect to these common units. See Note 18 for additional information regarding the Oiltanking acquisition and the Registration Rights Agreement.

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) and $2.75 billion of senior notes in October 2014 (see Note 18).

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 nine months ended September 30, 2014, we sold 1,590,334 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 nine months ended September 30, 2013, we sold 14,569,614 common units under the program for aggregate gross proceeds of $439.6 million, resulting in net cash proceeds of $435.5 million. After taking into account the aggregate sale price of common units sold under our at-the-market program through September 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 140,000,000 of our common units in connection with a distribution reinvestment plan (or "DRIP"). We issued 7,148,778 common units under our DRIP during the nine months ended September 30, 2014, which generated net cash proceeds of $240.0 million. During the nine months ended September 30, 2013, we issued 7,298,646 common units, which generated net cash proceeds of $206.0 million. After taking into account the number of common units issued under the DRIP through September 30, 2014, we have the capacity to issue an additional 29,812,978 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 nine months ended September 30, 2014, these EPCO affiliates reinvested $75.0 million, resulting in the issuance of 2,232,872 common units under our DRIP (this amount being a component of the total common units issued under the DRIP for the nine months ended September 30, 2014). On November 7, 2014, these EPCO affiliates reinvested an additional $25.0 million through the DRIP.

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of up to 8,000,000 of our common units in connection with an employee unit purchase plan (or "EUPP"). We issued 207,126 common units under our EUPP during the nine months ended September 30, 2014, which generated net cash proceeds of $7.4 million. During the nine months ended September 30, 2013, we issued 221,662 common units, which generated net cash proceeds of $6.6 million. After taking into account the number of common units issued under the EUPP through September 30, 2014, we may issue an additional 7,219,762 common units under this plan.

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

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

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 was completed on August 21, 2014 by distributing one additional common unit for each common unit outstanding (to holders of record as of the close of business on August 14, 2014).

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	16.1	--	--	16.1
Amounts reclassified from accumulated other comprehensive loss	12.9	23.9	--	36.8
Total other comprehensive income	29.0	23.9	--	52.9
Balance, September 30, 2014	$ 14.3	$ (323.3)	$ 2.9	$ (306.1)

	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	(22.1)	6.7	0.4	(15.0)
Amounts reclassified from accumulated other comprehensive loss	14.7	21.4	--	36.1
Total other comprehensive income (loss)	(7.4)	28.1	0.4	21.1
Balance, September 30, 2013	$ 2.7	$ (354.9)	$ 2.9	$ (349.3)

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

		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	Location	2014	2013	2014	2013
Losses (gains) on cash flow hedges:					
Interest rate derivatives	Interest expense	$ 8.0	$ 7.7	$ 23.9	$ 21.4
Commodity derivatives	Revenue	(17.8)	14.6	14.5	15.1
Commodity derivatives	Operating costs and expenses	(0.2)	--	(1.6)	(0.4)
Total		$ (10.0)	$ 22.3	$ 36.8	$ 36.1

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	$ 0.3350	4/30/2013	5/7/2013
2nd Quarter	$ 0.3400	7/31/2013	8/7/2013
3rd Quarter	$ 0.3450	10/31/2013	11/7/2013
2014:			
1st Quarter	$ 0.3550	4/30/2014	5/7/2014
2nd Quarter	$ 0.3600	7/31/2014	8/7/2014
3rd Quarter	$ 0.3650	10/31/2014	11/7/2014

As a result of the unit split completed on August 21, 2014, our historical distributions per unit were reduced (e.g., a $0.72 per unit distribution rate was adjusted to a $0.36 per unit distribution rate), but not the total amount of cash distributions paid since the number of common units outstanding doubled.

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 45,120,000 Designated Units. Distributions to be paid, if any, during 2015 will exclude 35,380,000 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues	$ 12,330.2	$ 12,093.3	$ 37,760.9	$ 34,625.7
Subtract operating costs and expenses	(11,414.8)	(11,273.5)	(34,934.4)	(32,061.1)
Add equity in income of unconsolidated affiliates	72.3	44.0	179.1	126.1
Add depreciation, amortization and accretion expense amounts not reflected in gross operating margin	322.7	285.2	936.5	851.7
Add impairment charges not reflected in gross operating margin	5.7	15.2	18.2	53.3
Subtract net gains attributable to asset sales and insurance recoveries not reflected in gross operating margin	(2.6)	(10.2)	(99.0)	(68.4)
Add non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	21.6	--	66.8	--
Total segment gross operating margin	$ 1,335.1	$ 1,154.0	$ 3,928.1	$ 3,527.3

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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Total segment gross operating margin	$ 1,335.1	$ 1,154.0	$ 3,928.1	$ 3,527.3
Adjustments to reconcile total segment gross operating margin to operating income:				
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(322.7)	(285.2)	(936.5)	(851.7)
Subtract impairment charges not reflected in gross operating margin	(5.7)	(15.2)	(18.2)	(53.3)
Add net gains attributable to asset sales and insurance recoveries not reflected in gross operating margin (see Note 16)	2.6	10.2	99.0	68.4
Subtract non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	(21.6)	--	(66.8)	--
Subtract general and administrative costs not reflected in gross operating margin	(50.0)	(43.9)	(150.9)	(138.9)
Operating income	937.7	819.9	2,854.7	2,551.8
Other expense, net	(230.8)	(207.7)	(679.8)	(604.2)
Income before income taxes	$ 706.9	$ 612.2	$ 2,174.9	$ 1,947.6

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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 September 30, 2014	$ 4,024.0	$ 1,026.5	$ 5,435.6	$ 41.1	$ 1,792.0	$ --	$ 12,319.2
Three months ended September 30, 2013	4,230.6	831.4	5,435.4	38.2	1,550.0	--	12,085.6
Nine months ended September 30, 2014	13,217.2	3,261.0	16,236.6	112.4	4,869.9	--	37,697.1
Nine months ended September 30, 2013	11,686.0	2,658.6	15,358.1	118.0	4,784.7	--	34,605.4
Revenues from related parties:							
Three months ended September 30, 2014	2.7	5.4	1.5	1.4	--	--	11.0
Three months ended September 30, 2013	0.1	4.1	2.1	1.4	--	--	7.7
Nine months ended September 30, 2014	10.2	16.5	31.1	6.0	--	--	63.8
Nine months ended September 30, 2013	0.6	12.1	2.1	5.5	--	--	20.3
Intersegment and intrasegment revenues:							
Three months ended September 30, 2014	3,603.8	231.0	2,529.5	1.2	452.2	(6,817.7)	--
Three months ended September 30, 2013	2,542.3	215.6	3,591.3	1.8	384.4	(6,735.4)	--
Nine months ended September 30, 2014	10,789.7	835.8	10,714.5	4.8	1,317.6	(23,662.4)	--
Nine months ended September 30, 2013	7,631.7	726.7	8,333.0	8.0	1,200.7	(17,900.1)	--
Total revenues:							
Three months ended September 30, 2014	7,630.5	1,262.9	7,966.6	43.7	2,244.2	(6,817.7)	12,330.2
Three months ended September 30, 2013	6,773.0	1,051.1	9,028.8	41.4	1,934.4	(6,735.4)	12,093.3
Nine months ended September 30, 2014	24,017.1	4,113.3	26,982.2	123.2	6,187.5	(23,662.4)	37,760.9
Nine months ended September 30, 2013	19,318.3	3,397.4	23,693.2	131.5	5,985.4	(17,900.1)	34,625.7
Equity in income (loss) of unconsolidated affiliates:							
Three months ended September 30, 2014	11.7	0.9	46.8	17.1	(4.2)	--	72.3
Three months ended September 30, 2013	4.1	1.0	34.3	9.8	(5.2)	--	44.0
Nine months ended September 30, 2014	19.2	2.7	131.7	35.8	(10.3)	--	179.1
Nine months ended September 30, 2013	11.8	2.9	101.0	24.9	(14.5)	--	126.1
Gross operating margin:							
Three months ended September 30, 2014	711.5	195.4	190.8	47.1	190.3	--	1,335.1
Three months ended September 30, 2013	639.6	213.4	146.0	37.9	117.1	--	1,154.0
Nine months ended September 30, 2014	2,172.4	618.8	534.5	120.0	482.4	--	3,928.1
Nine months ended September 30, 2013	1,777.0	601.9	579.6	118.1	450.7	--	3,527.3
Property, plant and equipment, net: (see Note 6)							
At September 30, 2014	11,768.9	8,834.7	1,540.6	1,168.2	2,845.2	1,805.7	27,963.3
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 September 30, 2014	685.8	23.5	1,651.7	502.4	74.9	--	2,938.3
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 September 30, 2014	264.6	983.6	3.6	43.9	95.4	--	1,391.1
At December 31, 2013	285.2	1,017.8	4.5	54.7	100.0	--	1,462.2
Goodwill: (see Note 8)							
At September 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 September 30, 2014	13,580.5	10,138.1	3,501.0	1,796.5	3,550.8	1,805.7	34,372.6
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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 3,603.4	$ 3,929.8	$ 12,029.8	$ 10,831.3
Midstream services	423.3	300.9	1,197.6	855.3
Total	4,026.7	4,230.7	13,227.4	11,686.6
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	775.5	590.7	2,515.7	1,954.1
Midstream services	256.4	244.8	761.8	716.6
Total	1,031.9	835.5	3,277.5	2,670.7
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	5,348.2	5,359.7	16,003.5	15,159.9
Midstream services	88.9	77.8	264.2	200.3
Total	5,437.1	5,437.5	16,267.7	15,360.2
Offshore Pipelines & Services:				
Sales of natural gas	--	0.1	0.2	0.3
Sales of crude oil	2.5	1.5	7.5	3.7
Midstream services	40.0	38.0	110.7	119.5
Total	42.5	39.6	118.4	123.5
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,605.4	1,390.1	4,338.2	4,271.5
Midstream services	186.6	159.9	531.7	513.2
Total	1,792.0	1,550.0	4,869.9	4,784.7
Total consolidated revenues	$ 12,330.2	$ 12,093.3	$ 37,760.9	$ 34,625.7
Consolidated costs and expenses				
Operating costs and expenses:				
Cost of sales	$ 10,455.1	$ 10,371.3	$ 32,213.1	$ 29,522.1
Other operating costs and expenses (1)	633.9	612.0	1,865.6	1,702.4
Depreciation, amortization and accretion	322.7	285.2	936.5	851.7
Net losses (gains) attributable to asset sales and insurance recoveries	(2.6)	(10.2)	(99.0)	(68.4)
Non-cash asset impairment charges	5.7	15.2	18.2	53.3
General and administrative costs	50.0	43.9	150.9	138.9
Total consolidated costs and expenses	$ 11,464.8	$ 11,317.4	$ 35,085.3	$ 32,200.0

(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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues – related parties:				
Unconsolidated affiliates	$ 11.0	$ 7.7	$ 63.8	$ 20.3
Costs and expenses – related parties:				
EPCO and affiliates	$ 212.8	$ 218.8	$ 688.0	$ 654.4
Unconsolidated affiliates	35.8	25.9	138.4	86.5
Total	$ 248.6	$ 244.7	$ 826.4	$ 740.9

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

	September 30, 2014	December 31, 2013
Accounts receivable - related parties:		
Unconsolidated affiliates	$ 2.6	$ 6.8
Accounts payable - related parties:		
EPCO and affiliates	$ 102.3	$ 116.3
Unconsolidated affiliates	20.3	34.2
Total	$ 122.6	$ 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 September 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
683,993,630	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 nine months ended September 30, 2014 and 2013, we paid EPCO and its privately held affiliates cash distributions totaling $652.8 million and $601.2 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Operating costs and expenses	$ 179.1	$ 190.5	$ 591.7	$ 564.7
General and administrative expenses	33.7	28.3	96.3	89.7
Total costs and expenses	$ 212.8	$ 218.8	$ 688.0	$ 654.4

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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
BASIC EARNINGS PER UNIT				
Net income attributable to limited partners	$ 691.1	$ 592.0	$ 2,127.6	$ 1,898.0
Undistributed earnings allocated and cash payments on phantom unit awards (1)	(1.3)	--	(4.0)	--
Net income available to common unitholders	$ 689.8	$ 592.0	$ 2,123.6	$ 1,898.0
Basic weighted-average number of common units outstanding	1,834.2	1,792.6	1,831.1	1,778.2
Basic earnings per unit	$ 0.38	$ 0.33	$ 1.16	$ 1.07
DILUTED EARNINGS PER UNIT				
Net income attributable to limited partners	$ 691.1	$ 592.0	$ 2,127.6	$ 1,898.0
Diluted weighted-average number of units outstanding:				
Distribution-bearing common units	1,834.2	1,792.6	1,831.1	1,778.2
Designated Units	45.1	47.4	45.1	47.4
Class B units (2)	--	3.8	--	7.2
Phantom units (1)	3.4	--	2.8	--
Incremental option units	0.7	2.2	1.0	2.4
Total	1,883.4	1,846.0	1,880.0	1,835.2
Diluted earnings per unit	$ 0.37	$ 0.32	$ 1.13	$ 1.03

(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 10 for information regarding a two-for-one common unit split announced on July 15, 2014 and completed on August 21, 2014.

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 September 30, 2014 and December 31, 2013, our accruals for litigation contingencies were $2.5 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 September 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 and October 2014 (see Note 18) 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 $23.5 million and $19.6 million during the third quarters of 2014 and 2013, respectively. For the nine months ended September 30, 2014 and 2013, consolidated lease and rental expense was $69.2 million and $64.9 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 $39 million over the next five years and $150 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 nine months ended September 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 nine months ended September 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 Nine Months Ended September 30,	
	2014	2013
Decrease (increase) in:		
Accounts receivable – trade	$ 153.6	$ (1,130.0)
Accounts receivable – related parties	4.0	(9.6)
Inventories	(536.9)	(674.2)
Prepaid and other current assets	(44.5)	(31.5)
Other assets	20.0	3.2
Increase (decrease) in:		
Accounts payable – trade	(14.2)	114.3
Accounts payable – related parties	(27.7)	(30.4)
Accrued product payables	(13.1)	1,358.1
Accrued interest	(131.7)	(132.6)
Other current liabilities	143.5	29.3
Other liabilities	11.2	(10.5)
Net effect of changes in operating accounts	$ (435.8)	$ (513.9)

We incurred liabilities for construction in progress that had not been paid at September 30, 2014 and December 31, 2013 of $264.9 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 Nine Months Ended September 30,	
	2014	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
Sale of pipeline linefill	7.4	65.0
Insurance recoveries attributable to West Storage claims (see Note 15)	95.0	8.8
Other cash proceeds	19.1	30.8
Total	$ 121.5	$ 256.3

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

	For the Nine Months Ended September 30,	
	2014	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 attributable to other asset sales	4.0	7.1
Total	$ 99.0	$ 68.4

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
September 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	$ 1,019.7	$ 52.1	$ (3.6)	$ 1,068.2	$ --	$ --	$ 1,068.2
Accounts receivable – trade, net	1,625.8	3,700.7	(5.7)	5,320.8	--	--	5,320.8
Accounts receivable – related parties	104.0	1,380.9	(1,481.8)	3.1	--	(0.5)	2.6
Inventories	1,244.3	346.2	(1.0)	1,589.5	--	--	1,589.5
Prepaid and other current assets	167.7	226.2	(10.3)	383.6	0.1	0.7	384.4
Total current assets	4,161.5	5,706.1	(1,502.4)	8,365.2	0.1	0.2	8,365.5
Property, plant and equipment, net	2,360.6	25,601.2	1.5	27,963.3	--	--	27,963.3
Investments in unconsolidated affiliates	32,198.8	3,452.0	(32,712.5)	2,938.3	15,758.0	(15,758.0)	2,938.3
Intangible assets, net	80.2	1,326.2	(15.3)	1,391.1	--	--	1,391.1
Goodwill	458.8	1,621.1	--	2,079.9	--	--	2,079.9
Other assets	124.5	44.7	(1.9)	167.3	0.1	--	167.4
Total assets	$ 39,384.4	$ 37,751.3	$ (34,230.6)	$ 42,905.1	$ 15,758.2	$ (15,757.8)	$ 42,905.5
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 1,939.9	$ --	$ --	$ 1,939.9	$ --	$ --	$ 1,939.9
Accounts payable – trade	304.5	426.9	(3.6)	727.8	0.2	--	728.0
Accounts payable – related parties	1,472.6	146.0	(1,496.0)	122.6	0.5	(0.5)	122.6
Accrued product payables	2,003.7	3,568.1	(7.2)	5,564.6	--	--	5,564.6
Accrued interest	172.2	0.3	--	172.5	--	--	172.5
Other current liabilities	63.1	392.4	(11.3)	444.2	--	--	444.2
Total current liabilities	5,956.0	4,533.7	(1,518.1)	8,971.6	0.7	(0.5)	8,971.8
Long-term debt	17,691.6	14.9	--	17,706.5	--	--	17,706.5
Deferred tax liabilities	4.3	57.3	(1.9)	59.7	--	3.5	63.2
Other long-term liabilities	10.4	172.2	(0.5)	182.1	--	--	182.1
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	15,722.1	32,903.7	(32,892.1)	15,733.7	15,757.5	(15,733.7)	15,757.5
Noncontrolling interests	--	69.5	182.0	251.5	--	(27.1)	224.4
Total equity	15,722.1	32,973.2	(32,710.1)	15,985.2	15,757.5	(15,760.8)	15,981.9
Total liabilities and equity	$ 39,384.4	$ 37,751.3	$ (34,230.6)	$ 42,905.1	$ 15,758.2	$ (15,757.8)	$ 42,905.5

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 September 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	$ 8,121.5	$ 8,598.2	$ (4,389.5)	$ 12,330.2	$ --	$ --	$ 12,330.2
Costs and expenses:							
Operating costs and expenses	7,950.9	7,853.5	(4,389.6)	11,414.8	--	--	11,414.8
General and administrative costs	8.2	40.4	--	48.6	1.4	--	50.0
Total costs and expenses	7,959.1	7,893.9	(4,389.6)	11,463.4	1.4	--	11,464.8
Equity in income of unconsolidated affiliates	762.5	94.4	(784.6)	72.3	692.5	(692.5)	72.3
Operating income	924.9	798.7	(784.5)	939.1	691.1	(692.5)	937.7
Other income (expense):							
Interest expense	(229.2)	(0.6)	--	(229.8)	--	--	(229.8)
Other, net	0.2	(1.2)	--	(1.0)	--	--	(1.0)
Total other expense, net	(229.0)	(1.8)	--	(230.8)	--	--	(230.8)
Income before income taxes	695.9	796.9	(784.5)	708.3	691.1	(692.5)	706.9
Provision for income taxes	(4.0)	(2.8)	--	(6.8)	--	(0.9)	(7.7)
Net income	691.9	794.1	(784.5)	701.5	691.1	(693.4)	699.2
Net loss (income) attributable to noncontrolling interests	--	0.1	(9.5)	(9.4)	--	1.3	(8.1)
Net income attributable to entity	$ 691.9	$ 794.2	$ (794.0)	$ 692.1	$ 691.1	$ (692.1)	$ 691.1

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Three Months Ended September 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	$ 7,070.3	$ 8,588.4	$ (3,565.4)	$ 12,093.3	$ --	$ --	$ 12,093.3
Costs and expenses:							
Operating costs and expenses	6,858.0	7,980.9	(3,565.4)	11,273.5	--	--	11,273.5
General and administrative costs	7.6	36.0	--	43.6	0.3	--	43.9
Total costs and expenses	6,865.6	8,016.9	(3,565.4)	11,317.1	0.3	--	11,317.4
Equity in income of unconsolidated affiliates	577.2	47.8	(581.0)	44.0	592.3	(592.3)	44.0
Operating income	781.9	619.3	(581.0)	820.2	592.0	(592.3)	819.9
Other income (expense):							
Interest expense	(208.0)	(0.3)	--	(208.3)	--	--	(208.3)
Other, net	0.1	0.5	--	0.6	--	--	0.6
Total other expense, net	(207.9)	0.2	--	(207.7)	--	--	(207.7)
Income before income taxes	574.0	619.5	(581.0)	612.5	592.0	(592.3)	612.2
Provision for income taxes	17.7	(36.8)	--	(19.1)	--	(0.3)	(19.4)
Net income	591.7	582.7	(581.0)	593.4	592.0	(592.6)	592.8
Net income attributable to noncontrolling interests	--	(0.2)	(1.6)	(1.8)	--	1.0	(0.8)
Net income attributable to entity	$ 591.7	$ 582.5	$ (582.6)	$ 591.6	$ 592.0	$ (591.6)	$ 592.0

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 Nine Months Ended September 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	$ 25,190.1	$ 25,859.9	$ (13,289.1)	$ 37,760.9	$ --	$ --	$ 37,760.9
Costs and expenses:							
Operating costs and expenses	24,516.6	23,707.6	(13,289.8)	34,934.4	--	--	34,934.4
General and administrative costs	23.1	126.0	--	149.1	1.8	--	150.9
Total costs and expenses	24,539.7	23,833.6	(13,289.8)	35,083.5	1.8	--	35,085.3
Equity in income of unconsolidated affiliates	2,169.5	256.1	(2,246.5)	179.1	2,129.4	(2,129.4)	179.1
Operating income	2,819.9	2,282.4	(2,245.8)	2,856.5	2,127.6	(2,129.4)	2,854.7
Other income (expense):							
Interest expense	(678.6)	(1.0)	--	(679.6)	--	--	(679.6)
Other, net	0.7	(0.9)	--	(0.2)	--	--	(0.2)
Total other expense, net	(677.9)	(1.9)	--	(679.8)	--	--	(679.8)
Income before income taxes	2,142.0	2,280.5	(2,245.8)	2,176.7	2,127.6	(2,129.4)	2,174.9
Provision for income taxes	(15.5)	(5.8)	0.2	(21.1)	--	(1.4)	(22.5)
Net income	2,126.5	2,274.7	(2,245.6)	2,155.6	2,127.6	(2,130.8)	2,152.4
Net loss (income) attributable to noncontrolling interests	--	0.2	(28.8)	(28.6)	--	3.8	(24.8)
Net income attributable to entity	$ 2,126.5	$ 2,274.9	$ (2,274.4)	$ 2,127.0	$ 2,127.6	$ (2,127.0)	$ 2,127.6

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Nine Months Ended September 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	$ 20,916.8	$ 24,044.5	$ (10,335.6)	$ 34,625.7	$ --	$ --	$ 34,625.7
Costs and expenses:							
Operating costs and expenses	20,328.5	22,068.2	(10,335.6)	32,061.1	--	--	32,061.1
General and administrative costs	19.7	118.0	--	137.7	1.2	--	138.9
Total costs and expenses	20,348.2	22,186.2	(10,335.6)	32,198.8	1.2	--	32,200.0
Equity in income of unconsolidated affiliates	1,936.2	141.9	(1,952.0)	126.1	1,899.2	(1,899.2)	126.1
Operating income	2,504.8	2,000.2	(1,952.0)	2,553.0	1,898.0	(1,899.2)	2,551.8
Other income (expense):							
Interest expense	(603.0)	(1.4)	--	(604.4)	--	--	(604.4)
Other, net	0.3	(0.1)	--	0.2	--	--	0.2
Total other expense, net	(602.7)	(1.5)	--	(604.2)	--	--	(604.2)
Income before income taxes	1,902.1	1,998.7	(1,952.0)	1,948.8	1,898.0	(1,899.2)	1,947.6
Provision for income taxes	(4.9)	(40.7)	--	(45.6)	--	(0.6)	(46.2)
Net income	1,897.2	1,958.0	(1,952.0)	1,903.2	1,898.0	(1,899.8)	1,901.4
Net income attributable to noncontrolling interests	--	(1.1)	(4.9)	(6.0)	--	2.6	(3.4)
Net income attributable to entity	$ 1,897.2	$ 1,956.9	$ (1,956.9)	$ 1,897.2	$ 1,898.0	$ (1,897.2)	$ 1,898.0

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 September 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	$ 708.9	$ 825.2	$ (784.5)	$ 749.6	$ 739.2	$ (741.5)	$ 747.3
Comprehensive loss (income) attributable to noncontrolling interests	--	0.1	(9.5)	(9.4)	--	1.3	(8.1)
Comprehensive income attributable to entity	$ 708.9	$ 825.3	$ (794.0)	$ 740.2	$ 739.2	$ (740.2)	$ 739.2

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Three Months Ended September 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	$ 583.4	$ 604.7	$ (580.9)	$ 607.2	$ 605.7	$ (606.4)	$ 606.5
Comprehensive income attributable to noncontrolling interests	--	(0.2)	(1.6)	(1.8)	--	1.0	(0.8)
Comprehensive income attributable to entity	$ 583.4	$ 604.5	$ (582.5)	$ 605.4	$ 605.7	$ (605.4)	$ 605.7

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 Nine Months Ended September 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	$ 2,161.8	$ 2,292.2	$ (2,245.5)	$ 2,208.5	$ 2,180.5	$ (2,183.7)	$ 2,205.3
Comprehensive loss (income) attributable to noncontrolling interests	--	0.2	(28.8)	(28.6)	--	3.8	(24.8)
Comprehensive income attributable to entity	$ 2,161.8	$ 2,292.4	$ (2,274.3)	$ 2,179.9	$ 2,180.5	$ (2,179.9)	$ 2,180.5

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Nine Months Ended September 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	$ 1,911.5	$ 1,964.7	$ (1,951.9)	$ 1,924.3	$ 1,919.1	$ (1,920.9)	$ 1,922.5
Comprehensive income attributable to noncontrolling interests	--	(1.1)	(4.9)	(6.0)	--	2.6	(3.4)
Comprehensive income attributable to entity	$ 1,911.5	$ 1,963.6	$ (1,956.8)	$ 1,918.3	$ 1,919.1	$ (1,918.3)	$ 1,919.1

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
For the Nine Months Ended September 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	$ 2,126.5	$ 2,274.7	$ (2,245.6)	$ 2,155.6	$ 2,127.6	$ (2,130.8)	$ 2,152.4
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	114.3	878.5	(0.4)	992.4	--	--	992.4
Equity in income of unconsolidated affiliates	(2,169.5)	(256.1)	2,246.5	(179.1)	(2,129.4)	2,129.4	(179.1)
Distributions received from unconsolidated affiliates	3,475.8	229.0	(3,444.1)	260.7	2,007.4	(2,007.4)	260.7
Net effect of changes in operating accounts and other operating activities	(764.6)	230.1	16.7	(517.8)	(5.6)	1.4	(522.0)
Net cash flows provided by operating activities	2,782.5	3,356.2	(3,426.9)	2,711.8	2,000.0	(2,007.4)	2,704.4
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(329.1)	(1,530.4)	--	(1,859.5)	--	--	(1,859.5)
Proceeds from asset sales and insurance recoveries	4.2	117.3	--	121.5	--	--	121.5
Other investing activities	(2,059.3)	(526.9)	2,056.1	(530.1)	(300.7)	300.7	(530.1)
Cash used in investing activities	(2,384.2)	(1,940.0)	2,056.1	(2,268.1)	(300.7)	300.7	(2,268.1)
Financing activities:							
Borrowings under debt agreements	7,167.5	--	--	7,167.5	--	--	7,167.5
Repayments of debt	(4,856.3)	--	--	(4,856.3)	--	--	(4,856.3)
Cash distributions paid to partners	(2,007.4)	(3,473.6)	3,473.6	(2,007.4)	(1,948.2)	2,007.4	(1,948.2)
Cash payments made in connection with DERs	--	--	--	--	(2.4)	--	(2.4)
Cash distributions paid to noncontrolling interests	--	--	(29.4)	(29.4)	--	--	(29.4)
Cash contributions from noncontrolling interests	--	--	4.0	4.0	--	--	4.0
Net cash proceeds from issuance of common units	--	--	--	--	304.9	--	304.9
Cash contributions from owners	300.7	2,060.0	(2,060.0)	300.7	--	(300.7)	--
Other financing activities	(18.1)	--	--	(18.1)	(53.6)	--	(71.7)
Cash provided by (used in) financing activities	586.4	(1,413.6)	1,388.2	561.0	(1,699.3)	1,706.7	568.4
Net change in cash and cash equivalents	984.7	2.6	17.4	1,004.7	--	--	1,004.7
Cash and cash equivalents, January 1	28.4	49.5	(21.0)	56.9	--	--	56.9
Cash and cash equivalents, September 30	$ 1,013.1	$ 52.1	$ (3.6)	$ 1,061.6	$ --	$ --	$ 1,061.6

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
For the Nine Months Ended September 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	$ 1,897.2	$ 1,958.0	$ (1,952.0)	$ 1,903.2	$ 1,898.0	$ (1,899.8)	$ 1,901.4
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	105.3	797.0	--	902.3	--	--	902.3
Equity in income of unconsolidated affiliates	(1,936.2)	(141.9)	1,952.0	(126.1)	(1,899.2)	1,899.2	(126.1)
Distributions received from unconsolidated affiliates	3,421.1	180.7	(3,414.2)	187.6	1,830.9	(1,830.9)	187.6
Net effect of changes in operating accounts and other operating activities	(1,371.4)	889.7	(11.0)	(492.7)	(6.6)	0.3	(499.0)
Net cash flows provided by operating activities	2,116.0	3,683.5	(3,425.2)	2,374.3	1,823.1	(1,831.2)	2,366.2
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(292.1)	(2,101.2)	--	(2,393.3)	--	--	(2,393.3)
Proceeds from asset sales and insurance recoveries	57.5	198.8	--	256.3	--	--	256.3
Other investing activities	(2,366.7)	(485.6)	2,051.8	(800.5)	(1,135.2)	1,135.2	(800.5)
Cash used in investing activities	(2,601.3)	(2,388.0)	2,051.8	(2,937.5)	(1,135.2)	1,135.2	(2,937.5)
Financing activities:							
Borrowings under debt agreements	10,139.2	--	--	10,139.2	--	--	10,139.2
Repayments of debt	(8,761.7)	(29.9)	--	(8,791.6)	--	--	(8,791.6)
Cash distributions paid to partners	(1,831.2)	(3,420.6)	3,420.6	(1,831.2)	(1,778.3)	1,831.2	(1,778.3)
Cash distributions paid to noncontrolling interests	--	--	(6.4)	(6.4)	--	--	(6.4)
Cash contributions from noncontrolling interests	--	--	104.2	104.2	--	--	104.2
Net cash proceeds from issuance of common units	--	--	--	--	1,134.7	--	1,134.7
Cash contributions from owners	1,135.2	2,155.9	(2,155.9)	1,135.2	--	(1,135.2)	--
Other financing activities	(192.6)	0.1	--	(192.5)	(44.5)	--	(237.0)
Cash provided by (used in) financing activities	488.9	(1,294.5)	1,362.5	556.9	(688.1)	696.0	564.8
Net change in cash and cash equivalents	3.6	1.0	(10.9)	(6.3)	(0.2)	--	(6.5)
Cash and cash equivalents, January 1	--	28.0	(12.1)	15.9	0.2	--	16.1
Cash and cash equivalents, September 30	$ 3.6	$ 29.0	$ (23.0)	$ 9.6	$ --	$ --	$ 9.6

Note 18. Subsequent Events

Acquisition of Oiltanking's General Partner and 65.9% of Oiltanking's Limited Partner Interests; Enterprise Proposes Merger of Oiltanking

On October 1, 2014, we announced our acquisition of the general partner and related incentive distribution rights, 15,899,802 common units and 38,899,802 subordinated units of Oiltanking Partners, L.P. ("Oiltanking") from Oiltanking Holding Americas, Inc. and its affiliates (collectively, "OTA"). We paid total consideration of approximately $4.41 billion to OTA comprised of $2.21 billion in cash and 54,807,352 of our common units. We also paid $228 million to acquire from OTA outstanding loans payable by Oiltanking or its subsidiaries. Collectively, these transactions are referred to as "Step 1" of the Oiltanking acquisition.

Oiltanking owns marine terminals located on the Houston Ship Channel and at the Port of Beaumont with a total of 12 ship and barge docks and approximately 24 MMBbls of crude oil and petroleum products storage capacity. Oiltanking's marine terminal on the Houston Ship Channel is connected by pipeline to our Mont Belvieu complex and is integral to our growing LPG export, octane enhancement and propylene businesses. Our Enterprise Crude Houston ("ECHO") facilities are also connected to Oiltanking's system.

We funded the cash consideration for Step 1 using borrowings under our new $1.5 billion 364-Day Credit Agreement (see Note 9), borrowings under our commercial paper program and cash on hand.

As a second step of the Oiltanking acquisition, we submitted a proposal to the conflicts committee of the general partner of Oiltanking to merge Oiltanking with a wholly owned subsidiary of ours (the "Proposed Merger"). Under the terms of the Proposed Merger, we would exchange 1.23 Enterprise common units for each Oiltanking common unit outstanding. The proposed consideration, valued at approximately $1.4 billion as of the offer date, represents an at-the-market value for Oiltanking common units based upon the volume weighted average trading prices of both Oiltanking and Enterprise common units on September 30, 2014. As a result, the total consideration for Step 1 of the Oiltanking acquisition and the Proposed Merger would approximate $6.0 billion.

The terms of the Proposed Merger are subject to negotiation, review and approval by the board of directors of our general partner and the conflicts committee of the board of directors of the general partner of Oiltanking. The Proposed Merger will also be subject to approval by holders of Oiltanking common units in accordance with the Oiltanking partnership agreement. We cannot predict whether the terms of a potential combination will be agreed upon by the conflicts committee of the board of directors of the general partner of Oiltanking or the board of directors of our general partner.

Upon payment of Oiltanking's distribution with respect to the third quarter of 2014, which is expected to be paid in mid-November 2014, the subordination period with respect to the Oiltanking subordinated units will end. At that time, the subordinated units we now own will convert into common units on a one-for-one basis. Upon conversion, we will own 54,799,604 Oiltanking common units, or approximately 65.9% of its outstanding common units.

In order to fund the equity consideration paid in Step 1, we issued 54,807,352 common units to OTA on October 1, 2014 in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act"), pursuant to Section 4(a)(2) thereof, and we granted OTA registration rights with respect to these common units under a Registration Rights Agreement between us and OTA (the "Registration Rights Agreement"). The Registration Rights Agreement provides that, subject to the terms and conditions set forth therein, at any time after the earlier of (i) 90 days after October 1, 2014 and (ii) the execution of definitive agreements to acquire (through merger or otherwise) all or substantially all of the Oiltanking common units not owned by Enterprise or its affiliates, OTA may request that we prepare and file a registration statement to permit and otherwise facilitate the public resale of all or a portion of the 54,807,352 Enterprise common units that OTA owns. Our obligation to OTA to effect such transactions is limited to five registration statements and underwritten offerings.

In connection with the Step 1 transaction, we entered into a Liquidity Option Agreement (the "Liquidity Option Agreement") with Marquard & Bahls, an affiliate of OTA ("M&B"). Pursuant to the Liquidity Option Agreement, we granted M&B the option (the "Liquidity Option") to sell to us 100% of the issued and outstanding capital stock of OTA (the "Option Securities"). The Liquidity Option may be exercised at any time within a 90-day period commencing on February 1, 2020. Pursuant to the Liquidity Option Agreement, the aggregate consideration to be paid by us for the Option Securities pursuant to the Liquidity Option would equal to 100% of the then-current fair market value of the OTA-owned Enterprise common units at the closing of the transactions contemplated under the Liquidity Option Agreement. The fair market value would be determined by multiplying the number of our common units owned by OTA at the time of exercise by the volume-weighted sales price per unit of our common units as reported by the New York Stock Exchange (or other national securities exchange, as applicable) for the ten

(10) consecutive trading days preceding the exercise. We may pay this consideration in all cash, all common units, or in any mix of cash or units, as determined solely by us.

If a defined "Trigger Event" occurs, the Liquidity Option may be exercised earlier within a 135-day period following notice of such event. Pursuant to the Liquidity Option Agreement, a "Trigger Event" means: (i) any transaction, event, circumstance, condition or state of facts by which our common units (or any other reference security) cease to be "regularly traded" within the meaning of Section 897 of the U.S. Internal Revenue Code (the "Code") and the Treasury Regulations thereunder; (ii) any transaction, event, circumstance, condition or state of facts by which OTA becomes the owner, for purposes of Section 897 of the Code, of our common units (or any other reference security) representing more than 5% of our outstanding common units (or such reference securities) other than as a result solely of the acquisition of our common units or other reference securities by OTA, M&B or any affiliate after the date of the Liquidity Option Agreement; or (iii) any "Enterprise Tax Event" as defined in the agreement, which includes certain events in which OTA would recognize taxable gain on the common units owned by OTA. The aggregate consideration to be paid by us for the Option Securities in connection with a Trigger Event exercise will be payable solely in cash, determined in the same manner as the price otherwise payable upon the exercise of the Liquidity Option. The Liquidity Option Agreement contains indemnification by M&B for certain specified liabilities of OTA following the closing of any exercise of the Liquidity Option, and certain conditions to closing.

OTA is wholly owned by an affiliate of Oiltanking GmbH, an independent storage provider for crude oil, refined products, liquid chemicals and gases. Dr. Christian Flach, managing director of Oiltanking GmbH and former chairman of the board of Oiltanking, has been named as a director of our general partner.

As a result of our acquisition of the general partner of Oiltanking, we began consolidating the financial statements of Oiltanking and its general partner on October 1, 2014. Prior to completion of the Proposed Merger, Oiltanking will also continue to file its periodic reports with the SEC.

In October 2014, EPCO amended the ASA to add Oiltanking and its general partner to the agreement. These new subsidiaries are entitled to receive services from EPCO on the same terms as services are being provided to us.

Issuance of $2.75 Billion of Senior Notes in October 2014

On October 14, 2014, EPO issued $800 million in principal amount of 2.55% senior notes due October 2019 ("Senior Notes LL"), $1.15 billion in principal amount of 3.75% senior notes due February 2025 ("Senior Notes MM") and $400 million in principal amount of 4.95% senior notes due October 2054 ("Senior Notes NN"). Senior Notes LL, MM and NN were issued at 99.981%, 99.681% and 98.356% of their principal amounts, respectively. EPO also issued an additional $400 million in principal amount of its 4.85% Senior Notes II due March 2044. The additional Senior Notes II were issued at 100.836% of their principal amount.

Net proceeds from the issuance of these senior notes of $2.73 billion were used as follows: (i) to repay debt principal amounts outstanding under EPO's 364-Day Credit Agreement and commercial paper program (both of which were used to partially fund the cash consideration paid in Step 1 of the Oiltanking acquisition), (ii) to repay $650.0 million in principal amount of Senior Notes G that matured in October 2014, and (iii) for general company purposes.

Enterprise Products Partners L.P. has unconditionally guaranteed these senior notes 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.

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

For the Three and Nine Months Ended September 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 September 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 U.S., Canada and Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations currently 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 52,000 miles of onshore and offshore pipelines; 220 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.

On October 1, 2014, we announced our acquisition of the general partner and certain limited partner interests of Oiltanking Partners, L.P. ("Oiltanking"). See "Significant Recent Developments" below for information regarding this subsequent event.

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 ("ASA") 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 (November 10, 2014). For information regarding recent offerings of our equity and debt securities, see "Liquidity and Capital Resources" within this Part I, Item 2.

Expansion of Eagle Ford Crude Oil Pipeline System

In November 2014, we, along with Plains All American Pipeline, L.P. ("Plains") announced an expansion of our Eagle Ford Crude Oil Pipeline System in South Texas. The expansion project entails the construction of a new 55-mile crude oil gathering system that will connect Karnes County and Live Oak County production areas in Texas to the joint venture's Three Rivers, Texas terminal. The joint venture will also construct an additional 70-mile, 20-inch pipeline from Three Rivers to Corpus Christi, Texas as well as expand storage and pumping capacity at Three Rivers. When combined with the expansion project announced in September 2013, this project effectively loops the Eagle Ford Crude Oil Pipeline System from Gardendale, Texas to Corpus Christi and increases the system's capacity to transport light and medium grades of crude oil to over 600 MBPD. These expansions are supported by a long-term production commitment and are expected to be placed into service in the third quarter of 2015.

Plains and Enterprise will also construct a new deep water terminal on the Corpus Christi ship channel to support the expected increase in crude oil volumes to be shipped via pipeline to the region. The dock is being designed to handle a variety of ocean-going vessels and is planned to be in service by 2017.

Acquisition of Oiltanking's General Partner and 65.9% of Oiltanking's Limited Partner Interests; Enterprise Proposes Merger of Oiltanking

On October 1, 2014, we announced our acquisition of the general partner and related incentive distribution rights, 15,899,802 common units and 38,899,802 subordinated units of Oiltanking Partners L.P. ("Oiltanking") from Oiltanking Holding Americas, Inc. and its affiliates (collectively, "OTA"). We paid total consideration of approximately $4.41 billion to OTA comprised of $2.21 billion in cash and 54,807,352 of our common units. We also paid $228 million to acquire from OTA outstanding loans payable by Oiltanking or its subsidiaries. Collectively, these transactions are referred to as "Step 1" of the Oiltanking acquisition.

Oiltanking owns marine terminals located on the Houston Ship Channel and at the Port of Beaumont with a total of 12 ship and barge docks and approximately 24 MMBbls of crude oil and petroleum products storage capacity. Oiltanking's marine terminal on the Houston Ship Channel is pipeline connected to our Mont Belvieu complex and is integral to our growing LPG export, octane enhancement and propylene businesses. Our Enterprise Crude Houston ("ECHO") facilities are also connected to Oiltanking's system.

We funded the cash consideration for Step 1 using borrowings under our new $1.5 billion 364-Day Credit Agreement, borrowings under our commercial paper program and cash on hand.

As a second step of the Oiltanking acquisition, we submitted a proposal to the conflicts committee of the general partner of Oiltanking to merge Oiltanking with a wholly owned subsidiary of ours (the "Proposed Merger"). Under the terms of the Proposed Merger, we would exchange 1.23 Enterprise common units for each Oiltanking common unit outstanding. The proposed consideration, valued at approximately $1.4 billion as of the offer date, represents an at-the-market value for Oiltanking common units based upon the volume weighted average trading prices of both Oiltanking and Enterprise common units on September 30, 2014. As a result, the total consideration for Step 1 of the Oiltanking acquisition and the Proposed Merger would approximate $6.0 billion.

The terms of the Proposed Merger are subject to negotiation, review and approval by the board of directors of our general partner and the conflicts committee of the board of directors of the general partner of Oiltanking. The Proposed Merger will also be subject to approval by holders of Oiltanking common units in accordance with the Oiltanking partnership agreement. We cannot predict whether the terms of a potential combination will be agreed upon by the conflicts committee of the board of directors of the general partner of Oiltanking or the board of directors of our general partner.

Upon payment of Oiltanking's distribution with respect to the third quarter of 2014, which is expected to be paid in mid-November 2014, the subordination period with respect to the Oiltanking subordinated units will end. At that time, the subordinated units we now own will convert into common units on a one-for-one basis. Upon conversion, we will own 54,799,604 Oiltanking common units, or approximately 65.9% of its outstanding common units.

In order to fund the equity consideration paid in Step 1, we issued 54,807,352 common units to OTA on October 1, 2014 in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act"), pursuant to Section 4(a)(2) thereof, and we granted OTA registration rights with respect to these common units under a Registration Rights Agreement between us and OTA (the "Registration Rights Agreement"). The Registration Rights Agreement provides that, subject to the terms and conditions set forth therein, at any time after the earlier of (i) 90 days after October 1, 2014 and (ii) the execution of definitive agreements to acquire (through merger or otherwise) all or substantially all of the Oiltanking common units not owned by Enterprise or its affiliates, OTA may request that we prepare and file a registration statement to permit and otherwise facilitate the public resale of all or a portion of the 54,807,352 Enterprise common units that OTA owns. Our obligation to OTA to effect such transactions is limited to five registration statements and underwritten offerings.

In connection with the Step 1 transaction, we entered into a Liquidity Option Agreement (the "Liquidity Option Agreement") with Marquard & Bahls, an affiliate of OTA ("M&B"). Pursuant to the Liquidity Option Agreement, we granted M&B the option (the "Liquidity Option") to sell to us 100% of the issued and outstanding capital stock of OTA (the "Option Securities"). The Liquidity Option may be exercised at any time within a 90-day period commencing on February 1, 2020. Pursuant to the Liquidity Option Agreement, the aggregate consideration to be paid by us for the Option Securities pursuant to the Liquidity Option would equal to 100% of the then-current fair market value of the OTA-owned Enterprise common units at the closing of the transactions contemplated under the Liquidity Option Agreement. The fair market value would be determined by multiplying the number of our common units owned by OTA at the time of exercise by the volume-weighted sales price per unit of our common units as reported by the New York Stock Exchange (or other national securities exchange, as applicable) for the ten (10) consecutive trading days preceding the exercise. We may pay this consideration in all cash, all common units, or in any mix of cash or units, as determined solely by us.

If a defined "Trigger Event" occurs, the Liquidity Option may be exercised earlier within a 135-day period following notice of such event. Pursuant to the Liquidity Option Agreement, a "Trigger Event" means: (i) any transaction, event, circumstance, condition or state of facts by which our common units (or any other reference security) cease to be "regularly traded" within the meaning of Section 897 of the U.S. Internal Revenue Code (the "Code") and the Treasury Regulations thereunder; (ii) any transaction, event, circumstance, condition or state of facts by which OTA becomes the owner, for purposes of Section 897 of the Code, of our common units (or any other reference security) representing more than 5% of our outstanding common units (or such reference securities) other than as a result solely of the acquisition of our common units or other reference securities by OTA, M&B or any affiliate after the date of the Liquidity Option Agreement; or (iii) any "Enterprise Tax Event" as defined in the agreement, which includes certain events in which OTA would recognize taxable gain on the common units owned by OTA. The aggregate consideration to be paid by us for the Option Securities in connection with a Trigger Event exercise will be payable solely in cash, determined in the same manner as the price otherwise payable upon the exercise of the Liquidity Option. The Liquidity Option Agreement contains indemnification by M&B for certain specified liabilities of OTA following the closing of any exercise of the Liquidity Option, and certain conditions to closing.

OTA is wholly owned by an affiliate of Oiltanking GmbH, an independent storage provider for crude oil, refined products, liquid chemicals and gases. Dr. Christian Flach, managing director of Oiltanking GmbH and former chairman of the board of Oiltanking, has been named as a director of our general partner.

As a result of our acquisition of the general partner of Oiltanking, we began consolidating the financial statements of Oiltanking and its general partner on October 1, 2014. Prior to completion of the Proposed Merger, Oiltanking will also continue to file its periodic reports with the U.S. Securities and Exchange Commission (the "SEC").

In October 2014, EPCO amended the ASA to add Oiltanking and its general partner to the agreement. These new subsidiaries are entitled to receive services from EPCO on the same terms as services are being provided to us.

Plans to Construct Additional Midstream Infrastructure to Serve the Delaware Basin

In September 2014, we announced plans to construct a new cryogenic natural gas processing plant in Eddy County, New Mexico and associated natural gas and NGL pipeline infrastructure to facilitate growing production of NGL-rich natural gas in the Delaware Basin, a prolific production area in West Texas and southern New Mexico. These assets are expected to begin operations in the first quarter of 2016. The South Eddy natural gas processing plant is expected to have an initial capacity of 200 MMcf/d of natural gas, with the potential for future expansions. Upon completion, this will bring our total natural gas processing plant capacity in the Delaware Basin to 400 MMcf/d.

To supply the new South Eddy plant, we plan to construct approximately 80 miles of natural gas gathering pipelines to complement our existing 1,500 miles of natural gas pipelines located in the Delaware Basin. We also expect to build a 75-mile, 12-inch diameter NGL pipeline to transport NGLs from the South Eddy plant to our Hobbs NGL fractionation and storage facility located in Gaines County, Texas. As a result of multiple pipeline connections at our Hobbs facility, shippers will have access to our NGL fractionation and storage complex in Mont Belvieu, Texas. Additionally, we plan to construct pipelines to deliver residue gas from the South Eddy plant to multiple third party pipelines.

Initial Stage of Aegis Ethane Pipeline Completed

In September 2014, we announced that the first segment, or 60 miles, of our Aegis Ethane Pipeline was complete and ready to commence ethane deliveries between our Mont Belvieu storage complex and Beaumont, Texas. The 270-mile Aegis Ethane Pipeline (or "Aegis") represents a key component of our planned ethane header system stretching from Corpus Christi, Texas to the Mississippi River in Louisiana. After taking into account existing South Texas midstream infrastructure and completion of the first segment of Aegis, this 500-mile ethane header system is now in service from Corpus Christi to Beaumont. The remainder of Aegis will be completed in two phases. The next segment between Beaumont and Lake Charles, Louisiana is expected to be completed in the third quarter of 2015. The final segment from Lake Charles to the Mississippi River is expected to be completed by the end of 2015.

Plans to Build Ninth NGL Fractionator at Our Mont Belvieu, Texas Complex

In September 2014, we announced plans to build a ninth NGL fractionator adjacent to our complex in Mont Belvieu, Texas. The new fractionator is expected to have a nameplate capacity of 85 MBPD and commence operations as early as January 2016. Once the ninth fractionator is placed into service, our aggregate nameplate NGL fractionation capacity will approximate 755 MBPD at Mont Belvieu and 1.2 MMBPD system-wide.

Upon completion of the ninth fractionator, we will have approximately 265 MBPD of propane production capability. We have secured the required permits and emission credits for the ninth and a possible, similarly-sized tenth NGL fractionator at Mont Belvieu. Our complex at Mont Belvieu features connectivity to our network of NGL supply and distribution pipelines, over 110 MMBbls of salt dome storage capacity and access to international markets through our existing LPG export facility and future ethane export facility (under construction).

Open Season for Proposed Bakken-to-Cushing Crude Oil Pipeline

In September 2014, we announced the start of a binding open commitment period to determine shipper interest in a proposed new crude oil pipeline (the "Bakken-to-Cushing" pipeline) that would originate in the Williston Basin of North Dakota and extend approximately 1,200 miles to the Cushing hub in Oklahoma. The proposed 30-inch diameter pipeline would also serve the Powder River and Denver-Julesburg production basins. The Bakken-to-Cushing pipeline would have the capability to transport up to six grades of crude oil and related products, including Rockies condensate and processed condensate.

If constructed, the Bakken-to-Cushing pipeline would have an initial throughput capacity of 340 MBPD and be expandable to approximately 700 MBPD. Subject to sufficient customer commitments, the pipeline would begin service in stages, starting with the Denver-Julesburg to Cushing segment in the fourth quarter of 2016, and be fully operational by the third quarter of 2017. The binding open commitment period extends to November 14, 2014.

SEKCO Oil Pipeline Completed

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

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 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 fourth 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 with a 40-foot draft that can accommodate Panamax size vessels that 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 long-term customer commitments. Ongoing expansion of the Beaumont refined products terminal, also supported by long-term customer commitments, includes the addition of a second dock and significant additional on-site storage and ancillary equipment for gasoline blending operations. 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, we will, through our Mont Belvieu facilities, 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.

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, which will 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues	$ 12,330.2	$ 12,093.3	$ 37,760.9	$ 34,625.7
Costs and expenses:				
Operating costs and expenses:				
Cost of sales	10,455.1	10,371.3	32,213.1	29,522.1
Other operating costs and expenses	633.9	612.0	1,865.6	1,702.4
Depreciation, amortization and accretion expenses	322.7	285.2	936.5	851.7
Net gains attributable to asset sales and insurance recoveries	(2.6)	(10.2)	(99.0)	(68.4)
Non-cash asset impairment charges	5.7	15.2	18.2	53.3
Total operating costs and expenses	11,414.8	11,273.5	34,934.4	32,061.1
General and administrative costs	50.0	43.9	150.9	138.9
Total costs and expenses	11,464.8	11,317.4	35,085.3	32,200.0
Equity in income of unconsolidated affiliates	72.3	44.0	179.1	126.1
Operating income	937.7	819.9	2,854.7	2,551.8
Interest expense	(229.8)	(208.3)	(679.6)	(604.4)
Other, net	(1.0)	0.6	(0.2)	0.2
Provision for income taxes	(7.7)	(19.4)	(22.5)	(46.2)
Net income	699.2	592.8	2,152.4	1,901.4
Net income attributable to noncontrolling interests	(8.1)	(0.8)	(24.8)	(3.4)
Net income attributable to limited partners	$ 691.1	$ 592.0	$ 2,127.6	$ 1,898.0

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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 3,603.4	$ 3,929.8	$ 12,029.8	$ 10,831.3
Midstream services	423.3	300.9	1,197.6	855.3
Total	4,026.7	4,230.7	13,227.4	11,686.6
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	775.5	590.7	2,515.7	1,954.1
Midstream services	256.4	244.8	761.8	716.6
Total	1,031.9	835.5	3,277.5	2,670.7
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	5,348.2	5,359.7	16,003.5	15,159.9
Midstream services	88.9	77.8	264.2	200.3
Total	5,437.1	5,437.5	16,267.7	15,360.2
Offshore Pipelines & Services:				
Sales of natural gas	--	0.1	0.2	0.3
Sales of crude oil	2.5	1.5	7.5	3.7
Midstream services	40.0	38.0	110.7	119.5
Total	42.5	39.6	118.4	123.5
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,605.4	1,390.1	4,338.2	4,271.5
Midstream services	186.6	159.9	531.7	513.2
Total	1,792.0	1,550.0	4,869.9	4,784.7
Total consolidated revenues	$ 12,330.2	$ 12,093.3	$ 37,760.9	$ 34,625.7

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
3rd Quarter	$ 4.07	$ 0.24	$ 1.04	$ 1.25	$ 1.28	$ 2.11	$ 0.71	$ 0.58	$ 97.21	$ 100.94
2014 Averages	$ 4.57	$ 0.29	$ 1.13	$ 1.30	$ 1.33	$ 2.15	$ 0.71	$ 0.59	$ 99.63	$ 103.64

(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 $0.99 per gallon during the third quarter of 2014 versus $1.01 per gallon during the third quarter of 2013 – a 2% quarter-to-quarter decrease. Ethane accounts for the largest volume of NGLs extracted from the natural gas stream. The price of ethane averaged $0.24 per gallon during the third quarter of 2014 compared to $0.25 per gallon during the third quarter of 2013. The weighted-average indicative market price for NGLs was $1.05 per gallon during the first nine months of 2014 versus $0.99 per gallon during the first nine months of 2013 – a 6% period-to-period increase. The price of ethane averaged $0.29 per gallon during the first nine months of 2014 compared to $0.26 per gallon during the first nine 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 $4.07 per MMBtu during the third quarter of 2014 versus $3.58 per MMBtu during the third quarter of 2013 – a 14% quarter-to-quarter increase. The market price of natural gas (as measured at the Henry Hub in Louisiana) averaged $4.57 per MMBtu during the first nine months of 2014 versus $3.67 per MMBtu during the first nine months of 2013 – a 25% 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 $97.21 per barrel during the third quarter of 2014 compared to $105.82 per barrel during the third quarter of 2013 – an 8% quarter-to-quarter decrease. The market price of WTI crude oil (as measured on the NYMEX) averaged $99.63 per barrel during the first nine months of 2014 compared to $98.14 per barrel during the first nine months of 2013 – a 2% 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 $100.94 per barrel during the third quarter of 2014 compared to $109.89 per barrel during the third quarter of 2013 and $103.64 per barrel during the first nine months of 2014 compared to $109.48 per barrel during the first nine 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. Revenues for the third quarter of 2014 increased $236.9 million when compared to the third quarter of 2013. Collectively, revenues from the marketing of natural gas and petrochemical and refined products increased $472.8 million quarter-to-quarter primarily due to higher sales prices, which accounted for a $277.0 million increase, and higher sales volumes, which accounted for an additional $195.8 million increase. Revenues from the marketing of NGLs decreased $326.4 million quarter-to-quarter primarily due to lower sales volumes, which accounted for a $295.8 million decrease. Likewise, revenues from the marketing of octane additives and high purity isobutylene ("HPIB") decreased a net $82.2 million quarter-to-quarter primarily due to lower sales volumes. Revenues from the marketing of crude oil decreased a net $10.5 million quarter-to-quarter primarily due to lower sales prices, which accounted for a $1.18 billion decrease, partially offset by higher sales volumes, which accounted for a $1.17 billion increase. Revenues from midstream services increased $173.8 million quarter-to-quarter primarily due to contributions from recently completed assets such as the ATEX pipeline and the Rocky Mountain expansion of our Mid-America Pipeline System as well as certain assets at our Mont Belvieu complex.

For the nine months ended September 30, 2014, revenues increased $3.14 billion when compared to the nine months ended September 30, 2013. Revenues from the marketing of NGLs increased $1.2 billion period-to-period primarily due to higher sales prices, which accounted for a $1.17 billion increase. Revenues from the marketing of crude oil increased a net $847.4 million period-to-period primarily due to higher sales volumes, which accounted for a $3.63 billion increase, partially offset by lower sales prices, which accounted for a $2.78 billion decrease. Collectively, revenues from the marketing of natural gas and refined products increased $955.5 million period-to-period primarily due to higher sales prices, which accounted for an $885.1 million increase. Revenues from the marketing of octane additives and HPIB decreased a net $305.2 million period-to-period primarily due to lower sales volumes, which in turn were attributable to lower production volumes caused by unscheduled plant maintenance outages. Revenues from midstream services increased $461.1 million period-to-period primarily due to contributions from recently completed assets such as the ATEX pipeline and 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.

Operating costs and expenses. Total operating costs and expenses for the third quarter of 2014 increased $141.3 million when compared to the third quarter of 2013 primarily due to an $83.8 million increase in cost of sales. Collectively, the cost of sales associated with our marketing of natural gas and petrochemical and refined products increased $400.3 million quarter-to-quarter primarily due to higher purchase costs, which accounted for a $237.9 million increase, and higher sales volumes, which accounted for an additional $162.4 million increase. Cost of sales associated with our marketing of crude oil increased a net $42.7 million quarter-to-quarter primarily due to higher sales volumes, which accounted for a $1.13 billion increase, partially offset by lower purchase costs, which accounted for a $1.08 billion decrease. The cost of sales associated with our marketing of NGLs decreased a net $284.2 million quarter-to-quarter primarily due to lower sales volumes, which accounted for a $299.9 million decrease. Cost of sales associated with our marketing of octane additives and HPIB decreased $66.1 million quarter-to-quarter primarily due to lower purchase costs, which accounted for a $49.7 million decrease, and lower sales volumes, which accounted for an additional $16.4 million decrease.

Other operating costs and expenses increased $21.9 million quarter-to-quarter, which includes $18.0 million of expense we recorded during the third quarter of 2014 related to a settlement with a producer on our San Juan Gathering System.

Depreciation, amortization and accretion expenses in operating costs and expenses increased $37.5 million for the third quarter of 2014 when compared to the third quarter of 2013 primarily due to recently constructed assets being placed into service.

For the nine months ended September 30, 2014, total operating costs and expenses increased $2.87 billion when compared to the nine months ended September 30, 2013 primarily due to a $2.69 billion increase in cost of sales. The cost of sales associated with our marketing of NGLs increased a net $1.11 billion period-to-period primarily due to higher purchase costs, which accounted for a $1.17 billion increase, partially offset by lower sales volumes, which accounted for a $64.2 million decrease. Cost of sales associated with our marketing of crude oil increased a net $989.3 million period-to-period primarily due to higher sales volumes, which accounted for a $3.49 billion increase, partially offset by lower purchase costs, which accounted for a $2.5 billion decrease. Collectively, the cost of sales associated with our marketing of natural gas and petrochemical and refined products increased a net $793.4 million period-to-period primarily due to higher purchase prices, which accounted for an $813.0 million increase, partially offset by lower sales volumes, which accounted for a $19.6 million decrease. Cost of sales associated with our marketing of octane additives and HPIB decreased $199.6 million period-to-period primarily due to lower purchase costs, which accounted for a $120.8 million decrease, and lower sales volumes, which accounted for an additional $78.8 million decrease.

Other operating costs and expenses increased $163.2 million period-to-period. The primary driver of this increase is the ongoing expansion of our operations, including that associated with recently completed assets being placed into service (e.g., our ATEX pipeline and expansion of the Rocky Mountain segment of our Mid-America Pipeline System). We estimate that this factor accounted for approximately $100 million of the $163.2 million increase in expense. In addition, the period-to-period increase includes (i) $18.0 million of expense we recorded in the third quarter of 2014 in connection with a producer settlement involving our San Juan Gathering System, (ii) a $16.6 million benefit we recognized in the first quarter of 2013, which represents a negative variance period-to-period, attributable to reductions in a provision for certain pipeline capacity obligations and (iii) lower volumetric measurement gains of $13.9 million period-to-period.

Depreciation, amortization and accretion expenses in operating costs and expenses increased $84.8 million for the first nine months of 2014 when compared to the first nine months of 2013 primarily due to recently constructed assets being placed into service.

We recorded net gains within operating costs and expenses of $99.0 million attributable to asset sales and insurance recoveries in the first nine months of 2014 compared to $68.4 million in the first nine 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 nine months of 2014 compared to $8.8 million of such gains in the first nine months 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. General and administrative costs for the third quarter of 2014 increased $6.1 million when compared to the third quarter of 2013 primarily due to higher employee compensation costs, which accounted for $5.3 million of the increase, and transaction costs associated with the Oiltanking acquisition, which accounted for $1.2 million of the increase. For the nine months ended September 30, 2014, general and administrative costs increased $12.0 million when compared to the same period in 2013 primarily due to higher employee compensation costs, which accounted for $6.6 million of the increase, transaction costs of $1.2 million associated with the Oiltanking acquisition, and $4.7 million of settlement costs associated with litigation associated with the merger of Enterprise GP Holdings L.P.

Equity in income of unconsolidated affiliates. Equity income from our unconsolidated affiliates increased $28.3 million for the third quarter of 2014 and $53.0 million for the nine months ended September 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. Interest expense increased $21.5 million for the third quarter of 2014 and $75.2 million for the nine months ended September 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Interest charged on debt principal outstanding	$ 240.3	$ 229.3	$ 713.6	$ 682.2
Impact of interest rate hedging program, including related amortization	1.6	1.5	4.6	2.0
Interest costs capitalized in connection with construction projects (1)	(17.2)	(27.8)	(53.4)	(95.1)
Other (2)	5.1	5.3	14.8	15.3
Total	$ 229.8	$ 208.3	$ 679.6	$ 604.4

(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 $11.0 million quarter-to-quarter primarily due to increased debt principal amounts outstanding during the third quarter of 2014, which accounted for a $17.4 million increase, partially offset by the effect of lower overall interest rates in the third quarter of 2014, which accounted for a $6.4 million decrease. Our weighted-average debt principal balance for the third quarter of 2014 was $18.77 billion compared to $17.25 billion for the third 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 nine months ended September 30, 2014, interest charged on debt principal outstanding increased a net $31.4 million period-to-period primarily due to increased debt principal amounts outstanding during the first nine months of 2014, which accounted for a $52.0 million increase, partially offset by the effect of lower overall interest rates in the first nine months of 2014, which accounted for a $20.6 million decrease. Our weighted-average debt principal balance for the first nine months of 2014 was $18.29 billion compared to $17.03 billion for the first nine months of 2013.

Provision for income taxes. Provision for income taxes decreased $11.7 million for the third quarter of 2014 and $23.7 million for the nine months ended September 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").

Noncontrolling interests. Net income attributable to noncontrolling interests increased $7.3 million for the third quarter of 2014 and $21.4 million for the nine months ended September 30, 2014 when compared to the same respective periods in 2013 primarily due to increased earnings by the underlying joint ventures.

Business Segment Highlights

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. The following table presents gross operating margin by segment for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Non-GAAP gross operating margin by segment:				
NGL Pipelines & Services	$ 711.5	$ 639.6	$ 2,172.4	$ 1,777.0
Onshore Natural Gas Pipelines & Services	195.4	213.4	618.8	601.9
Onshore Crude Oil Pipelines & Services	190.8	146.0	534.5	579.6
Offshore Pipelines & Services	47.1	37.9	120.0	118.1
Petrochemical & Refined Products Services	190.3	117.1	482.4	450.7
Total	$ 1,335.1	$ 1,154.0	$ 3,928.1	$ 3,527.3

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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Segment gross operating margin:				
Natural gas processing and related NGL marketing activities	$ 290.5	$ 293.4	$ 905.4	$ 826.9
NGL pipelines and related storage	277.7	230.7	828.9	650.7
NGL fractionation	143.3	115.5	438.1	299.4
Total	$ 711.5	$ 639.6	$ 2,172.4	$ 1,777.0
Selected volumetric data:				
NGL transportation volumes (MBPD)	2,866	2,867	2,862	2,717
NGL fractionation volumes (MBPD)	823	736	820	707
Equity NGL production (MBPD) (1)	103	120	125	120
Fee-based natural gas processing (MMcf/d) (2)	4,958	4,660	4,872	4,589

(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 third quarter of 2014 decreased $2.9 million when compared to the third quarter of 2013. Gross operating margin from our NGL marketing activities for the third quarter of 2014 decreased $47.9 million when compared to the third quarter of 2013 primarily due to lower margins and volumes resulting from downtime at our Houston Ship Channel LPG export terminal during the third quarter of 2014. In the third quarter of 2014, more volume in the LPG export business was associated with long-term, fee-based contracts as opposed to higher margin spot business in the third quarter of 2013.

Gross operating margin from our Pioneer natural gas processing plant in Wyoming increased $19.3 million quarter-to-quarter primarily due to higher equity NGL production volumes of 8 MBPD, which accounted for an $18.6 million increase. Gross operating margin from our South Texas natural gas processing plants increased a net

$16.6 million quarter-to-quarter primarily due to (i) higher processing margins, which accounted for a $28.6 million increase, (ii) higher fee-based processing volumes of 107 MMcf/d and higher fees, which accounted for a combined $7.9 million increase, partially offset by (iii) lower equity NGL production volumes of 21 MBPD, which accounted for a $20.8 million decrease. Our South Texas gas plants experienced higher levels of ethane rejection during the third quarter of 2014 relative to the third quarter of 2013, which resulted in the lower equity NGL production volumes. Gross operating margin from our natural gas processing plants in Louisiana and our Indian Basin natural gas processing plant in New Mexico increased a combined $8.0 million quarter-to-quarter primarily due to higher volumes. Equity NGL production and fee-based natural gas processing volumes at these plants for the third quarter of 2014 increased 11 MBPD and 235 MMcf/d, respectively, when compared to the third quarter of 2013. Gross operating margin from our Meeker natural gas processing plant in Colorado increased a net $3.1 million quarter-to-quarter primarily due to (i) higher processing margins, which accounted for a $10.2 million increase, (ii) a $4.4 million quarter-to-quarter decrease in operating expenses, partially offset by (iii) lower equity NGL production volumes of 15 MBPD, which accounted for an $11.1 million decrease.

Gross operating margin from natural gas processing and related NGL marketing activities for the nine months ended September 30, 2014 increased $78.5 million when compared to the same period in 2013. Gross operating margin from our NGL marketing activities for the first nine months of 2014 increased $10.3 million when compared to the first nine months of 2013 primarily due to higher sales volumes, particularly those attributable to our Houston Ship Channel LPG export terminal, which was completed in March 2013.

Gross operating margin from our Pioneer natural gas processing plant increased a net $45.6 million period-to-period primarily due to higher equity NGL production volumes of 10 MBPD, which accounted for a $52.9 million increase, partially offset by lower processing margins, which accounted for a $9.1 million decrease. Gross operating margin from our South Texas natural gas processing plants increased $36.7 million period-to-period primarily due to (i) higher processing fees, which accounted for a $20.0 million increase, (ii) higher fee-based processing volumes of 160 MMcf/d, which accounted for a $9.8 million increase and (iii) higher processing margins, which accounted for a $6.6 million increase. Gross operating margin from our Indian Basin natural gas processing plant increased $8.3 million period-to-period primarily due to a 1 MBPD increase in equity NGL production and a 73 MMcf/d increase in fee-based natural gas processing volumes.

Gross operating margin from our Meeker natural gas processing plant decreased a net $23.3 million period-to-period primarily due to (i) lower processing margins, which accounted for a $17.4 million decrease, (ii) lower equity NGL production volumes of 10 MBPD, which accounted for a $12.0 million decrease, partially offset by (iii) higher processing fees, which accounted for a $4.5 million increase.

NGL pipelines and related storage

Gross operating margin from NGL pipelines and related storage assets for the third quarter of 2014 increased $47.0 million when compared to the third quarter of 2013 primarily due to the start-up of our ATEX pipeline and strong results from our Mid-America Pipeline System and Seminole Pipeline. Our ATEX pipeline commenced operations in January 2014 and contributed $34.6 million of gross operating margin during the third quarter of 2014 and 66 MBPD of transportation volumes. Gross operating margin for ATEX for the third quarter of 2014 includes $11.7 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 $10.2 million quarter-to-quarter primarily due to higher revenues from ship-or-pay agreements in the third quarter of 2014 associated with the recent expansion of our Rocky Mountain pipeline. In the aggregate, transportation volumes for the Mid-America Pipeline System and Seminole Pipeline decreased a net 60 MBPD quarter-to-quarter.

Collectively, gross operating margin from our investments in the Front Range Pipeline, Texas Express Pipeline and Texas Express Gathering System increased $9.0 million quarter-to-quarter, which includes $1.5 million of transportation revenues associated with shipper make-up rights that are deferred under GAAP and not reflected in our consolidated equity income. Net to our interest, aggregate transportation volumes on these three systems were 79 MBPD during the third quarter of 2014. Gross operating margin from our Houston Ship Channel LPG export terminal and related pipeline decreased $7.8 million quarter-to-quarter primarily due to a combined 44 MBPD decrease in volumes. Our LPG export terminal resumed operations on July 7, 2014 after experiencing a 12-day outage for maintenance and activities to prepare for the 2015 terminal expansion.

Gross operating margin from NGL pipelines and related storage assets for the nine months ended September 30, 2014 increased $178.2 million when compared to the same period in 2013. Our ATEX pipeline contributed $100.7 million of gross operating margin during the first nine months of 2014 and 47 MBPD of transportation volumes. Gross operating margin for ATEX for the first nine months of 2014 includes $45.5 million of transportation revenues associated with shipper make-up rights that are deferred under GAAP and not reflected in our consolidated revenues. Collectively, gross operating margin from our investments in the Front Range Pipeline, Texas Express Pipeline and Texas Express Gathering System increased $14.9 million period-to-period, which includes $6.9 million of transportation revenues associated with shipper make-up rights that are deferred under GAAP and not reflected in our consolidated equity income. Net to our interest, aggregate transportation volumes on these three pipeline systems were 55 MBPD during the first nine months of 2014.

Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased a combined $40.1 million period-to-period. The increase in gross operating margin is primarily due to a $77.4 million increase in transportation revenues attributable to the Rocky Mountain pipeline expansion and higher system-wide tariffs, partially offset by a $30.0 million increase in operating costs (e.g., higher fuel and maintenance costs) and a $7.0 million decrease in revenues attributable to a 17 MBPD decline in transportation volumes.

Gross operating margin from our South Texas NGL Pipeline System increased $22.6 million period-to-period primarily due to a 62 MBPD increase in transportation volumes primarily associated with Eagle Ford Shale production.

NGL fractionation

Gross operating margin from NGL fractionation for the third quarter of 2014 increased $27.8 million when compared to the third quarter of 2013. Gross operating margin for our Mont Belvieu NGL fractionators increased $37.3 million quarter-to-quarter primarily due to increased mixed NGL production 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 114 MBPD quarter-to-quarter (net to our ownership interest), which resulted in a net $37.2 million quarter-to-quarter increase in gross operating margin after taking into account associated operating costs. We placed our seventh and eighth NGL fractionators at Mont Belvieu into service during the third and fourth quarters of 2013, respectively. Collectively, gross operating margin from our Norco fractionator in Louisiana and Hobbs fractionator in Texas decreased $10.1 million quarter-to-quarter primarily due to combined lower fractionation volumes of 35 MBPD, partially due to ethane rejection.

Gross operating margin from NGL fractionation for the nine months ended September 30, 2014 increased $138.7 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 130 MBPD period-to-period (net to our ownership interest), which resulted in a $111.0 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 $35.8 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Segment gross operating margin	$ 195.4	$ 213.4	$ 618.8	$ 601.9
Selected volumetric data:				
Natural gas transportation volumes (BBtus/d)	12,486	12,969	12,541	13,115

Gross operating margin from our onshore natural gas pipelines and services segment for the third quarter of 2014 decreased $18.0 million when compared to the third quarter of 2013.

Gross operating margin from our San Juan Gathering System decreased a net $12.4 million quarter-to-quarter primarily due to $18.0 million of expense we recorded during the third quarter of 2014 for the settlement of a contract dispute with a producer, partially offset by a $3.9 million decrease in operating costs primarily attributable to lower maintenance expenses and pipeline measurement imbalances. Gathering volumes on this system decreased 34 BBtus/d quarter-to-quarter. Gross operating margin from our Texas Intrastate System decreased a net $2.1 million quarter-to-quarter primarily due to (i) lower transportation volumes, which accounted for a $1.1 million decrease, (ii) higher maintenance and other operating expenses, which accounted for a $4.1 million decrease, partially offset by (iii) higher fees, which accounted for a $3.4 million increase. Natural gas transportation volumes for the Texas Intrastate System decreased 133 BBtus/d quarter-to-quarter.

Gross operating margin from our Haynesville Gathering System decreased $3.0 million quarter-to-quarter primarily due to a 224 BBtus/d decrease in gathering volumes. Certain producers in the lean gas resource basin served by this gathering system 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 nine months ended September 30, 2014 increased $16.9 million when compared to the same period in 2013. Gross operating margin from our natural gas marketing activities increased $20.2 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 $20.9 million period-to-period primarily due to higher pipeline and storage revenues in the first nine months of 2014, which accounted for a $18.4 million increase, and lower maintenance and other operating costs in the first nine months of 2014, which accounted for an additional $4.0 million increase. Transportation revenues on the Texas Intrastate System increased $10.0 million period-to-period primarily due to higher average fees. In addition, firm capacity reservation fees on the Texas Intrastate System increased $5.4 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 decreased 11 BBtus/d period-to-period.

Gross operating margin from our San Juan Gathering System decreased a net $6.0 million period-to-period. Higher gathering fees, which are indexed to natural gas prices and accounted for an $11.9 million increase, were partially offset by a 43 BBtus/d decrease in gathering volumes, which accounted for a $4.0 million decrease. In addition, gross operating margin from our San Juan Gathering System for the third quarter of 2014 includes $18.0 million of expense for the settlement of a contract dispute with a producer. Collectively, gross operating margin from our Jonah and Piceance Basin Gathering Systems decreased $7.5 million period-to-period primarily due to a combined 224 BBtus/d decrease in gathering volumes. Lastly, gross operating margin from our Haynesville Gathering System decreased $9.7 million period-to-period primarily due to a 188 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 September 30,		For the Nine Months Ended September 30,	
	2014	**2013**	**2014**	**2013**
Segment gross operating margin	$ 190.8	$ 146.0	$ 534.5	$ 579.6
Selected volumetric data:				
Crude oil transportation volumes (MBPD)	1,266	1,252	1,274	1,139

Gross operating margin from our onshore crude oil pipelines and services segment for the third quarter of 2014 increased $44.8 million when compared to the third quarter of 2013. Gross operating margin from our South Texas Crude Oil Pipeline System and West Texas System increased a combined $7.2 million quarter-to-quarter primarily due to an aggregate 18 MBPD increase in transportation volumes primarily from Eagle Ford Shale and Permian Basin developments. Equity earnings from our investment in the Eagle Ford Crude Oil Pipeline System increased $6.9 million quarter-to-quarter on a 56 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 $13.7 million quarter-to-quarter primarily due to a tariff rate increase that went into effect in July 2014 applicable to transportation volumes on Seaway's Longhaul System. Overall, Seaway's transportation volumes decreased 74 MBPD quarter-to-quarter (net to our interest) primarily due to lower volumes on its Texas City System. Gross operating margin from our ECHO and Midland storage terminals increased $14.7 million quarter-to-quarter primarily due to measurement gains in the third quarter of 2014 versus measurement losses in the third quarter of 2013 at both locations.

Gross operating margin from our onshore crude oil pipelines and services segment for the nine months ended September 30, 2014 decreased $45.1 million when compared to the same period in 2013. Gross operating margin from our crude oil marketing and related activities decreased $163.6 million period-to-period primarily due to lower sales margins attributable to decreases in regional price spreads for crude oil. For example, the average indicative price spread between LLS and WTI crude oil was $11.34 per barrel in the first nine months of 2013 compared to $4.01 per barrel in the first nine months of 2014. Gross operating margin from our South Texas Crude Oil Pipeline System and West Texas System increased a combined $64.2 million period-to-period primarily due to a combined 70 MBPD increase in transportation volumes. Equity earnings from our investment in the Eagle Ford Crude Oil Pipeline System increased $25.8 million period-to-period on a 60 MBPD increase in transportation volumes (net to our interest).

Gross operating margin from our investment in the Seaway Pipeline increased $18.9 million period-to-period primarily due to the tariff rate increases in July 2013 and July 2014. Gross operating margin from our ECHO storage terminal increased $14.7 million period-to-period primarily due to net measurement gains of $9.7 million in the first nine months of 2014 when compared to the same period in 2013 and higher storage volumes, which accounted for a $7.4 million increase.

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 September 30,		For the Nine Months Ended September 30,	
	2014	**2013**	**2014**	**2013**
Segment gross operating margin	$ 47.1	$ 37.9	$ 120.0	$ 118.1
Selected volumetric data:				
Natural gas transportation volumes (BBtus/d)	683	665	621	706
Platform natural gas processing (MMcf/d)	152	185	150	217
Crude oil transportation volumes (MBPD)	335	314	329	306
Platform crude oil processing (MBPD)	16	16	14	15

Gross operating margin from our offshore pipelines and services segment for the third quarter of 2014 increased $9.2 million when compared to the third quarter of 2013. Gross operating margin for the third quarter of 2014 includes $6.5 million of equity earnings from our investment in the SEKCO Oil Pipeline, which started earning firm capacity reservation fees in July 2014. Equity earnings from our investment in the Cameron Highway Oil Pipeline increased $1.0 million quarter-to-quarter primarily due to a 17 MBPD increase (net to our interest) in crude oil transportation volumes. Collectively, gross operating margin from our Constitution and Allegheny Oil Pipelines increased $1.3 million quarter-to-quarter primarily due to a combined 14 MBPD increase in transportation volumes.

Crude oil production in the Gulf of Mexico continues to improve. Currently, there are 41 drilling ships and deepwater semi-submersible drilling rigs active in the Gulf of Mexico region (U.S. waters) and another 11 vessels are expected to arrive before the end of 2015. Approximately half of this drilling fleet is focused on existing production fields, many of which are connected to our assets. Our offshore crude oil pipelines averaged 335 MBPD in the third quarter of 2014, which reflects a continued improvement since the first quarter of 2010.

Gross operating margin from this segment for the first nine months of 2014 increased $1.9 million when compared to the first nine months of 2013. Gross operating margin for the first nine months of 2014 includes $6.5 million of equity earnings from our investment in the SEKCO Oil Pipeline, which started earning firm capacity reservation fees in the third quarter of 2014. Equity earnings from our investment in the Cameron Highway Oil Pipeline increased $4.9 million period-to-period primarily due to a 25 MBPD increase (net to our interest) in crude oil transportation volumes. In the aggregate, gross operating margin from our Independence Hub platform and Independence Trail pipeline decreased $13.5 million period-to-period primarily due to lower platform processing and pipeline throughput volumes during the first nine months of 2014. Natural gas processing volumes on the Independence Hub platform decreased 80 MMcf/d period-to-period (net to our interest) and natural gas transportation volumes on the Independence Trail pipeline decreased 92 BBtus/d period-to-period.

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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Segment gross operating margin:				
Propylene fractionation and related activities	$ 65.4	$ 27.9	$ 156.4	$ 89.0
Butane isomerization and related operations	11.6	27.4	65.8	78.2
Octane enhancement and related plant operations	48.2	40.8	94.7	122.1
Refined products pipelines and related activities	48.1	2.8	114.2	108.1
Marine transportation and other	17.0	18.2	51.3	53.3
Total	$ 190.3	$ 117.1	$ 482.4	$ 450.7
Selected volumetric data:				
Propylene fractionation volumes (MBPD)	73	74	72	71
Butane isomerization volumes (MBPD)	95	100	93	94
Standalone DIB processing volumes (MBPD)	86	79	81	66
Octane additive and related plant production volumes (MBPD)	20	19	15	18
Transportation volumes, primarily refined products and petrochemicals (MBPD)	778	711	746	693

Propylene fractionation and related activities

Gross operating margin from propylene fractionation and related activities for the third quarter of 2014 increased $37.5 million when compared to the third quarter of 2013. This increase was primarily due to (i) higher sales margins, which accounted for a $15.6 million increase, (ii) higher propylene sales volumes, which accounted for a $6.9 million increase and (iii) lower operating expenses of $12.0 million at our Mont Belvieu propylene fractionators primarily due to rescheduling of certain maintenance activities to the second quarter of 2015.

Gross operating margin from our propylene fractionation and related activities increased $67.4 million for the nine months ended September 30, 2014 when compared to the same period in 2013. This increase was primarily due to (i) higher propylene sales margins, which accounted for a $41.7 million increase, (ii) higher propylene sales volumes, which accounted for a $3.5 million increase, (iii) a $7.1 million increase in propylene fractionation fee revenues and (iv) lower operating expenses of $14.5 million at our Mont Belvieu propylene fractionators primarily due to rescheduling of certain maintenance activities to the second quarter of 2015.

Butane isomerization and deisobutanizer operations

Gross operating margin from our butane isomerization and deisobutanizer operations decreased an aggregate $15.8 million for the third quarter of 2014 when compared to the third quarter of 2013. Likewise, gross operating margin from these operations decreased an aggregate $12.4 million for the first nine months of 2014 when compared to the same period in 2013. These decreases are primarily due to maintenance costs we incurred during the third quarter of 2014 involving these assets.

Octane enhancement and HPIB plant operations

Gross operating margin from our octane enhancement facility and HPIB plant increased a combined $7.4 million quarter-to-quarter. The increase in gross operating margin is primarily due to higher sales margins in the third quarter of 2014 compared to the third quarter of 2013.

Gross operating margin from these businesses decreased a combined $27.4 million for the first nine 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 and reduced operating rates during the second and third quarters of 2014. Production volumes at our octane enhancement facility averaged 14 MBPD for the first nine months of 2014 compared to 16 MBPD during the same period in 2013.

Refined products pipelines and related activities

Gross operating margin from our refined products pipelines and related marketing activities for the third quarter of 2014 increased $45.3 million when compared to the third quarter of 2013. Gross operating margin from our TE Products Pipeline and related refined products terminals increased $49.1 million quarter-to-quarter. Transportation revenues on our TE Products Pipeline increased $8.8 million quarter-to-quarter primarily due to higher fees. In addition, operating costs for the TE Products Pipeline and related terminals decreased $42.8 million quarter-to-quarter primarily due to (i) lower maintenance expenses of $25.3 million associated with pipeline integrity and related projects and (ii) lower storage costs of $9.1 million associated with repurposing segments of the TE Products Pipeline to be used by the ATEX pipeline and the associated reduction in pipeline storage requirements. Components of the TE Products Pipeline were removed from service during the third quarter of 2013 and repurposed to accommodate the southbound delivery of ethane on our ATEX pipeline, which commenced operations in January 2014. Overall, transportation volumes for the TE Products Pipeline increased 61 MBPD quarter-to-quarter primarily due to higher intrastate shipments of petrochemicals and refined products in southeast Texas. Gross operating margin from our refined products marketing activities decreased $5.2 million quarter-to-quarter primarily due to lower sales margins.

Gross operating margin from our refined products pipelines and related marketing activities for the first nine months of 2014 increased $6.1 million when compared to the same period of 2013. Gross operating margin from our TE Products Pipeline and related refined products terminals increased $5.7 million period-to-period primarily due to lower pipeline integrity expenses of $14.3 million and higher transportation tariffs and other fees of $8.7 million, partially offset by a $16.6 million benefit recorded in the first quarter of 2013 related to reductions in a provision for future pipeline capacity obligations on a third party pipeline. Overall, transportation volumes for the TE Products Pipeline increased a net 47 MBPD period-to-period primarily due to higher intrastate shipments of petrochemicals and refined products in southeast Texas, which accounted for a combined 72 MBPD increase, partially offset by lower interstate transportation volumes for refined products and NGLs of 25 MBPD. Gross operating margin from our refined products marketing activities decreased $4.1 million period-to-period primarily due to lower sales margins.

Liquidity and Capital Resources

At September 30, 2014, we had $4.77 billion of consolidated liquidity, which was comprised of $1.06 billion of unrestricted cash on hand and $3.71 billion of available borrowing capacity under EPO's revolving credit facilities. 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. Unrestricted cash on hand at September 30, 2014 increased due to proceeds from the issuance of commercial paper notes in September 2014 in anticipation of funding the cash consideration required in connection with Step 1 of the Oiltanking transaction on October 1, 2014.

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 $19.67 billion of principal amounts outstanding under consolidated debt agreements at September 30, 2014. The following table presents scheduled maturities of our consolidated debt obligations outstanding at September 30, 2014 for the periods indicated (dollars in millions):

		Scheduled Maturities of Debt					
	Total	Remainder of 2014	2015	2016	2017	2018	After 2018
Commercial Paper	$ 1,290.0	$ 1,290.0	$ --	$ --	$ --	$ --	$ --
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	$ 19,672.7	$ 1,940.0	$ 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.

Senior Notes Issued in 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.

In October 2014, EPO issued $800 million in principal amount of 2.55% senior notes due October 2019 ("Senior Notes LL"), $1.15 billion in principal amount of 3.75% senior notes due February 2025 ("Senior Notes MM") and $400 million in principal amount of 4.95% senior notes due October 2054 ("Senior Notes NN"). Senior Notes LL, MM and NN were issued at 99.981%, 99.681% and 98.356% of their principal amounts, respectively. EPO also issued an additional $400 million in principal amount of its 4.85% Senior Notes II due March 2044. The additional Senior Notes II were issued at 100.836% of their principal amount. Net proceeds from the issuance of these senior notes of $2.73 billion were used as follows: (i) to repay debt principal amounts outstanding under EPO's 364-Day Credit Agreement (as discussed below) and commercial paper program (both of which were used to partially fund the cash consideration paid in Step 1 of the Oiltanking acquisition (see "Significant Recent Developments" within this Part I, Item 2)), (ii) to repay $650.0 million in principal amount of Senior Notes G that matured in October 2014, and (iii) for general company purposes.

New $1.5 Billion 364-Day Credit Agreement due September 2015. On September 30, 2014, EPO entered into a new 364-Day Revolving Credit Agreement (the "364-Day Credit Agreement"). Under the terms of the 364-Day Credit Agreement, EPO may borrow up to $1.5 billion (which may be increased by up to $200 million to $1.7 billion at EPO's election) at a variable interest rate for a term of 364 days, subject to the terms and conditions set forth therein. On October 1, 2014, we borrowed $1.5 billion under the 364-Day Credit Agreement to partially fund the cash consideration paid under Step 1 of the Oiltanking acquisition (see "Significant Recent Developments" within this Part I, Item 2). This amount was subsequently repaid using proceeds from the issuance of senior notes in October 2014.

To the extent that principal amounts are outstanding, EPO's obligations under the 364-Day Credit Agreement are not secured by any collateral; however, they are guaranteed by Enterprise Products Partners L.P. Any amounts borrowed under the 364-Day Credit Agreement mature on September 29, 2015, although EPO may, between 15 and 60 days prior to the maturity date, elect to have the entire principal balance then outstanding continued as non-revolving term loans for a period of one additional year, payable on September 29, 2016.

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.

Issuance of Common Units

On October 1, 2014, in order to fund the equity consideration paid in Step 1 of the Oiltanking acquisition, we issued 54,807,352 common units to OTA. Pursuant to a Registration Rights Agreement, we granted the seller registration rights with respect to these common units. See "Significant Recent Developments" within this Part I, Item 2 for additional information regarding the Oiltanking acquisition and the Registration Rights Agreement.

The following information describes significant transactions that affected our partners' equity accounts during the nine months ended September 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 nine months ended September 30, 2014, we issued 1,590,334 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 September 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 7,148,778 common units under our distribution reinvestment plan ("DRIP") during the nine months ended September 30, 2014, which generated net cash proceeds of $240.0 million. After taking into account the number of common units issued under the DRIP through September 30, 2014, we have the capacity to issue an additional 29,812,978 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 nine months ended September 30, 2014, these EPCO affiliates reinvested $75.0 million, resulting in the issuance of 2,232,872 common units under our DRIP (this amount being a component of the total common units issued under the DRIP for the nine months ended September 30, 2014). On November 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 our common units in connection with our employee unit purchase plan ("EUPP"). We issued 207,126 common units under our EUPP during the nine months ended September 30, 2014, which generated net cash proceeds of $7.4 million. After taking into account the number of common units issued under the EUPP through September 30, 2014, we may issue an additional 7,219,762 common units under this plan.

Use of proceeds. The net cash proceeds we received from the issuance of common units during the nine months ended September 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

On July 15, 2014, we announced that our general partner approved a two-for-one split of our common units. The common unit split was completed on August 21, 2014 by distributing one additional common unit for each common unit outstanding (to holders of record as of the close of business on August 14, 2014). All per unit amounts and number of Enterprise units outstanding in this quarterly report on Form 10-Q are presented on a post-split basis.

Credit Ratings

As of November 10, 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 Nine Months Ended September 30,	
	2014	2013
Net cash flows provided by operating activities	$ 2,704.4	$ 2,366.2
Cash used in investing activities	2,268.1	2,937.5
Cash provided by financing activities	568.4	564.8

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 Nine Months Ended September 30, 2014 with Nine Months Ended September 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 nine months of 2014 increased $338.2 million when compared to the first nine months of 2013. The increase in cash provided by operating activities was primarily due to:

- a $187.0 million increase in cash attributable to higher partnership income in the first nine months of 2014 compared to the first nine months of 2013 (after adjusting our $251.0 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);

- a $78.1 million period-to-period increase in cash attributable to the timing of cash receipts and disbursements related to operations; and

- a $73.1 million period-to-period increase in cash distributions from unconsolidated affiliates primarily due to increased earnings from our investments in crude oil and NGL pipeline joint ventures (e.g., our Eagle Ford Crude Oil Pipeline System, Texas Express Pipeline, Seaway Pipeline and Front Range Pipeline).

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 nine months of 2014 decreased $669.4 million when compared to the first nine months of 2013 primarily due to:

- a $533.8 million period-to-period decrease in capital expenditures for consolidated property, plant and equipment, net of contributions in aid of construction costs (see "Capital Spending" within this Part I, Item 2 for additional information regarding our capital spending program);

- a $185.1 million period-to-period decrease in cash contributions to our unconsolidated affiliates primarily due to the completion of construction of the Texas Express Pipeline, SEKCO Oil Pipeline and Front Range Pipeline, partially offset by increased investments in the Seaway Pipeline related to its pipeline looping project; and

- a $90.6 million period-to-period change in restricted cash requirements; partially offset by

- an aggregate $134.8 million period-to-period decrease in cash proceeds from asset sales and insurance recoveries. See Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report for additional information regarding proceeds from asset sales and insurance recoveries.

***Financing Activities*.** Our net cash inflow from financing activities was $568.4 million during the first nine months of 2014 compared to $564.8 million for the first nine months of 2013. The $3.6 million period-to-period increase in cash flow from financing activities was primarily due to:

- a $963.6 million period-to-period increase in net borrowings under our consolidated debt agreements. EPO issued $2.0 billion and repaid $500.0 million in principal amount of senior notes during the first nine 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 nine months of 2013. In addition, net borrowings under EPO's commercial paper program and revolving credit facility increased $512.0 million period-to-period; and

- a $168.8 million period-to-period decrease in cash payments related to the monetization of interest rate derivative instruments during the first nine months of 2013. There were no such transactions during the first nine months of 2014; partially offset by

- an $829.8 million period-to-period decrease in net cash proceeds from the issuance of common units. We issued an aggregate 8,946,238 common units in connection with our DRIP, EUPP and at-the-market program during the first nine months of 2014, which generated $304.9 million of net cash proceeds. This compares to an aggregate 40,489,922 common units we issued in connection with an underwritten offering and our DRIP, EUPP and at-the-market program during the first nine months of 2013, which collectively generated $1.13 billion of net cash proceeds;

- a $169.9 million increase in cash distributions paid to limited partners during the first nine months of 2014 compared to the first nine months of 2013. The increase in cash distributions is due to increases in both the number of distribution-bearing common units outstanding and the quarterly cash distribution rates per unit; and

- a $100.2 million period-to-period decrease in cash contributions from noncontrolling interests primarily due to contributions we received during the second quarter of 2013 related to a joint venture involving NGL fractionators at our complex in Mont Belvieu, Texas.

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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income attributable to limited partners (1)	$ 691.1	$ 592.0	$ 2,127.6	$ 1,898.0
Adjustments to GAAP net income attributable to limited partners to derive non-GAAP distributable cash flow:				
Add depreciation, amortization and accretion expenses	341.4	302.5	992.4	902.3
Add asset impairment charges	5.7	15.2	18.2	53.3
Subtract net gains attributable to asset sales and insurance recoveries	(2.6)	(10.2)	(99.0)	(68.4)
Add cash proceeds from asset sales and insurance recoveries (2)	8.3	57.1	121.5	256.3
Add cash distributions received from unconsolidated affiliates (3)	103.6	68.3	260.7	187.6
Subtract equity in income of unconsolidated affiliates (3)	(72.3)	(44.0)	(179.1)	(126.1)
Subtract sustaining capital expenditures (4)	(106.8)	(81.8)	(262.0)	(213.9)
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	2.0	17.3	2.6	32.1
Other, net	4.4	(8.8)	32.7	(23.1)
Distributable cash flow	$ 974.8	$ 907.6	$ 3,015.6	$ 2,729.3
Total cash distributions paid to limited partners with respect to period	$ 691.1	$ 622.0	$ 2,002.6	$ 1,822.7
Cumulative quarterly cash distributions per unit declared by Enterprise GP with respect to period (6)	$ 0.365	$ 0.345	$ 1.08	$ 1.02
Total distributable cash flow retained by partnership with respect to period (7)	$ 283.7	$ 285.6	$ 1,013.0	$ 906.6
Distribution coverage ratio (8)	1.4x	1.5x	1.5x	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 of this quarterly report.
(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 of this quarterly report.
(6) See Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report 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 the 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.

See "Significant Recent Developments" within this Part I, Item 2 for information regarding our recently announced acquisition of Oiltanking's general partner and 65.9% of Oiltanking's limited partner interests for approximately $4.6 billion.

We placed approximately $3.9 billion of major capital projects into service during the first nine 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 $320 million during the remainder of 2014. These projects include various product handling projects (e.g., natural gasoline treating and degassing) at our Mont Belvieu complex.

At September 30, 2014, we had approximately $1.51 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 Nine Months Ended September 30, 2014 with Nine Months Ended September 30, 2013

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

	For the Nine Months Ended September 30,	
	2014	**2013**
Capital spending for property, plant and equipment, net: (1)		
Growth capital projects (2)	$ 1,598.3	$ 2,183.8
Sustaining capital projects (3)	261.2	209.5
Investments in unconsolidated affiliates	583.3	768.4
Other investing activities	6.0	1.0
Total capital spending	$ 2,448.8	$ 3,162.7

(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 $20.0 million and $19.9 million for the nine months ended September 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. 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 nine months ended September 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 our LPG, ethane and refined products export terminals.

Capital spending for property, plant and equipment for the first nine months of 2014 decreased $533.8 million compared to the same period of 2013. This decrease in capital spending was primarily due to a decrease in growth capital expenditures of $585.5 million period-to-period, which was partially offset by an increase in sustaining capital expenditures of $51.7 million period-to-period, largely attributable to increased expenditures for pipeline integrity and similar projects.

Capital spending for growth projects at our Mont Belvieu complex and in the Eagle Ford Shale decreased a combined $485.1 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 and Aegis ethane pipelines decreased a net $331.9 million period-to-period. Our ATEX pipeline was placed into service in January 2014 and delivers ethane produced in the northeastern U.S. to our Mont Belvieu, Texas storage complex. Construction on the initial phase of Aegis was completed in September 2014 with full operations expected to commence by the end of 2015. Aegis is connected to our Mont Belvieu complex and is expected to have a transportation capacity of up to 425 MBPD of purity ethane volumes.

Growth capital spending for our LPG, ethane and refined products export facilities increased $173.6 million period-to-period. The announced expansions of our LPG export terminal located on the Houston Ship Channel are expected to increase its ability to load cargoes from 7.5 MMBbls per month to approximately 16.0 MMBbls per month and are expected to be completed in two phases by the end of 2015. In April 2014, we announced plans to construct a fully refrigerated ethane export facility located on the Houston Ship Channel, which we expect to begin operations in the third quarter of 2016. In May 2014, we began loading cargoes of refined products for export at our reactivated marine terminal located on the Neches River in Beaumont, Texas.

Investments in unconsolidated affiliates for the first nine months of 2014 decreased $185.1 million when compared to the same period of 2013. Our spending on the expansion and construction of joint venture crude oil pipelines increased a net $45.1 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

Excluding our recently announced $4.6 billion business combination with Oiltanking, we expect total capital spending for 2014 to approximate $3.5 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Expensed	$ 17.6	$ 28.5	$ 44.4	$ 57.4
Capitalized	11.5	16.0	30.5	38.6
Total	$ 29.1	$ 44.5	$ 74.9	$ 96.0

We expect the cost of our pipeline integrity program, regardless of whether such costs are capitalized or expensed, to approximate $42.0 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.

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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Total segment gross operating margin	$ 1,335.1	$ 1,154.0	$ 3,928.1	$ 3,527.3
Adjustments to reconcile total segment gross operating margin to operating income:				
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(322.7)	(285.2)	(936.5)	(851.7)
Subtract impairment charges not reflected in gross operating margin	(5.7)	(15.2)	(18.2)	(53.3)
Add net gains attributable to asset sales and insurance recoveries not reflected in gross operating margin	2.6	10.2	99.0	68.4
Subtract non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	(21.6)	--	(66.8)	--
Subtract general and administrative costs not reflected in gross operating margin	(50.0)	(43.9)	(150.9)	(138.9)
Operating income	937.7	819.9	2,854.7	2,551.8
Other expense, net	(230.8)	(207.7)	(679.8)	(604.2)
Income before income taxes	$ 706.9	$ 612.2	$ 2,174.9	$ 1,947.6

<u>Distributable cash flow</u>. 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 September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Distributable cash flow	$ 974.8	$ 907.6	$ 3,015.6	$ 2,729.3
Adjustments to reconcile distributable cash flow to net cash flows provided by operating activities:				
Add sustaining capital expenditures reflected in distributable cash flow	106.8	81.8	262.0	213.9
Subtract cash proceeds from asset sales and insurance recoveries reflected in distributable cash flow	(8.3)	(57.1)	(121.5)	(256.3)
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	(237.2)	(104.7)	(435.8)	(513.9)
Other, net	(3.6)	7.7	(15.9)	24.4
Net cash flows provided by operating activities	$ 832.5	$ 835.3	$ 2,704.4	$ 2,366.2

Contractual Obligations

Our consolidated debt principal obligations at September 30, 2014 were approximately $19.67 billion compared to $17.36 billion at December 31, 2013. For information regarding the scheduled maturities of such debt, see "Liquidity and Capital Resources – Consolidated Debt" within this Part I, Item 2. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report for additional 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 $39 million over the next five years and $150 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 nine months ended September 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 nine months ended September 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 September 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

The following table shows the effect of hypothetical interest rate movements (a sensitivity analysis) on the estimated fair value 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	September 30, 2014	October 17, 2014 (1)
Fair value assuming no change in underlying interest rates	*Asset*	$ 24.8	$ 19.4	$ --
Fair value assuming 10% increase in underlying interest rates	*Asset*	24.1	18.9	--
Fair value assuming 10% decrease in underlying interest rates	*Asset*	25.5	19.9	--

(1) As a result of market conditions in early October 2014, we elected to terminate all interest rate swaps then outstanding; therefore, there were no swaps to report as of October 17, 2014.

As a result of market conditions in early October 2014, we elected to terminate all of our outstanding interest rate swaps. We terminated 10 fixed-to-floating swaps outstanding at September 30, 2014 having an aggregate notional value of $750 million, which resulted in cash gains totaling $17.6 million. In addition, we terminated 16 fixed-to-floating swaps having a total notional value of $800 million entered into in connection with the issuance of Senior Notes LL in October 2014. The early termination of these 16 swaps resulted in cash gains totaling $10.0 million. Since both groups of swaps were accounted for as fair value hedges, the aggregate $27.6

million of gains will be carried as a component of long-term debt and be amortized into earnings (as a decrease in interest expense) using the effective interest method over the remaining life of the associated debt obligations. The $17.6 million gain will be amortized through January 2016 and the $10.0 million gain will be amortized through October 2019.

In July 2014, six undesignated floating-to-fixed swaps having an aggregate notional amount of $600.0 million expired. These swaps were accounted for as mark-to-market instruments with changes in fair value recorded in interest expense.

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 September 30, 2014 (volume measures as noted):

	Volume (1)		
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Accounting Treatment**
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	1.1	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	0.3	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	0.3	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	0.2	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted sales of natural gas (Bcf)	1.7	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	5.1	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	5.2	0.1	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	8.8	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.7	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.3	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	5.0	0.5	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	7.0	0.5	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (4,5)	63.5	15.3	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	6.7	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 December 2015, October 2015 and March 2018, respectively.
(3) Forecasted sales of NGL volumes under natural gas processing exclude 0.3 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.
(4) Current and long-term volumes include 28.9 Bcf and 0.9 Bcf, respectively, 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 October 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):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2013	Portfolio Fair Value at September 30, 2014	Portfolio Fair Value at October 17, 2014
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (1.3)	$ (0.5)	$ 4.4
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(6.7)	(4.6)	0.5
Fair value assuming 10% decrease in underlying commodity prices	*Asset*	4.1	3.6	8.2

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):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2013	Portfolio Fair Value at September 30, 2014	Portfolio Fair Value at October 17, 2014
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (20.7)	$ 12.7	$ 35.0
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(69.8)	(11.2)	15.6
Fair value assuming 10% decrease in underlying commodity prices	*Asset*	28.5	36.6	54.3

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):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2013	Portfolio Fair Value at September 30, 2014	Portfolio Fair Value at October 17, 2014
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ 8.2	$ 7.5	$ 19.9
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(9.8)	(10.7)	4.8
Fair value assuming 10% decrease in underlying commodity prices	*Asset*	26.1	25.6	35.0

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 third 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.

On occasion, we are assessed monetary sanctions by governmental authorities related to administrative or judicial proceedings involving environmental matters. We do not expect such expenditures to be material to our consolidated financial statements. In August 2014, following a Notice of Violation sent to us in the third quarter of

2013, we received information from the New Mexico Oil Conservation Division that they expect to assess us a penalty in connection with violations involving a hydrostatic test permit for a pipeline project in Santa Fe County, New Mexico. The eventual resolution of these matters may result in monetary sanctions in excess of $0.1 million.

Item 1A. *Risk Factors*.

An investment in our securities involves certain risks. Security holders and potential investors in our securities should carefully consider the supplemental risk described below in addition to the risks described under "Risk Factors" as set forth in Part I, Item 1A of our 2013 Form 10-K, in addition to other information in such annual report. The risk factors set forth in this quarterly report and 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.

The following risks relate to the Proposed Merger of Oiltanking with a wholly-owned subsidiary of ours. For information regarding the Proposed Merger, see "Significant Recent Developments" under Part I, Item 2 of this quarterly report.

Risks Related to Oiltanking Acquisition and the Proposed Merger

The Proposed Merger may not be approved by the board of our general partner, the Oiltanking conflicts committee and board, and the Oiltanking unitholders, or the terms on which such approval might be granted may differ from the initially proposed terms.

In connection with the announcement of the acquisition of Oiltanking's general partner and limited partner interests, we proposed that we would acquire Oiltanking pursuant to the terms of the Proposed Merger. Prior to entering into a definitive agreement with respect to the Proposed Merger, each of the board of our general partner, the Oiltanking conflicts committee and board, and the Oiltanking unitholders will be required to approve the Proposed Merger. In connection with obtaining such approval, the terms of the Proposed Merger, including the exchange ratio by which Oiltanking common units would be converted into our common units in connection with the Proposed Merger, will be subject to negotiation with each of the board of our general partner, the Oiltanking conflicts committee and board, and the Oiltanking unitholders. The board of our general partner, the Oiltanking conflicts committee and board, and the Oiltanking unitholders may not approve the Proposed Merger, or if such approval is granted, the terms on which the Proposed Merger is approved may be significantly different than the initially proposed terms. Further, the market prices of our and Oiltanking's common units could fluctuate significantly prior to the consummation of the Proposed Merger and any potential changes in the market prices of our or Oiltanking's common units could affect whether the board of our general partner, the Oiltanking conflicts committee and board, or the Oiltanking unitholders will approve the Proposed Merger, or if such approval is granted, the terms on which the Proposed Merger will be approved**.**

The failure to successfully combine Oiltanking with our business following the Proposed Merger may adversely affect our future results.

If the Proposed Merger is consummated, the success of the Proposed Merger between us and Oiltanking will depend, in part, on our ability to realize the anticipated benefits from combining the businesses of Enterprise and Oiltanking. To realize these anticipated benefits, Enterprise's and Oiltanking's businesses must be successfully combined and to realize the anticipated benefits of the Proposed Merger, further transactions must be successfully negotiated, approved and implemented. If the combined company is not able to achieve these objectives, the anticipated benefits of the Proposed Merger may not be realized fully or at all or may take longer to realize than expected. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the Proposed Merger.

Enterprise and Oiltanking, including their respective subsidiaries, have operated and, until the completion of the Proposed Merger, will continue to operate independently. It is possible that the integration process could result in the loss of key employees, as well as the disruption of each company's ongoing businesses or inconsistencies in their standards, controls, procedures and policies. Any or all of those occurrences could adversely affect the combined company's ability to maintain relationships with customers and employees after the Proposed Merger or to achieve the anticipated benefits of the Proposed Merger. Integration efforts between the two companies will also divert management attention and resources. These integration matters could have an adverse effect on us.

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

The following table summarizes our repurchase activity during the nine months ended September 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)	842,782	$ 32.85	--	--
May 2014 (2)	26,386	$ 36.62	--	--
August 2014 (3)	8,849	$ 37.52	--	--

(1) Of the 2,479,724 restricted common units that vested in February 2014 and converted to common units, 842,782 units were sold back to us by employees to cover related withholding tax requirements.
(2) Of the 73,800 restricted common units that vested in May 2014 and converted to common units, 26,386 units were sold back to us by employees to cover related withholding tax requirements.
(3) Of the 32,874 restricted common units that vested in August 2014 and converted to common units, 8,849 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).
2.12	Contribution and Purchase Agreement, dated as of October 1, 2014, by and among Enterprise Products Partners L.P., Oiltanking Holding Americas, Inc. and OTB Holdco, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2014).
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	Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 21, 2014 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 26, 2014).
3.6	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).
3.7	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).
3.8	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).
3.9	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).

3.10	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).
3.11	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	Twenty-Sixth Supplemental Indenture, dated as of October 14, 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 4.4 to Form 8-K filed October 14, 2014).
4.29	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).
4.30	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).
4.31	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).
4.32	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).
4.33	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).
4.34	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).

4.35	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).
4.36	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.37	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).
4.38	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).
4.39	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).
4.40	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).
4.41	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).
4.42	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).
4.43	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).
4.44	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).
4.45	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).
4.46	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).
4.47	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).
4.48	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).
4.49	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).
4.50	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).
4.51	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).
4.52	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).
4.53	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).
4.54	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).
4.55	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).
4.56	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).
4.57	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).
4.58	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).
4.59	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).
4.60	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).

4.61	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).
4.62	Form of Global Note representing $800.0 million principal amount of 2.55% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 14, 2014).
4.63	Form of Global Note representing $1.15 billion principal amount of 3.75% Senior Notes due 2025 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 14, 2014).
4.64	Form of Global Note representing $400.0 million principal amount of 4.95% Senior Notes due 2054 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 14, 2014).
4.65	Form of Global Note representing $400.0 million principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 14, 2014).
4.66	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).
4.67	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).
4.68	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).
4.69	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).
4.70	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).
4.71	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).
4.72	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).
4.73	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).
4.74	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).
4.75	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).

4.76	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).
4.77	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).
4.78	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).
4.79	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).
4.80	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).
4.81	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).
4.82	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).
4.83	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).
4.84	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).
4.85	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).
4.86	Registration Rights Agreement by and between Enterprise Products Partners L.P. and Oiltanking Holding Americas, Inc. dated as of October 1, 2014 (incorporated by reference to Exhibit 4.1 to Form 8-K filed on October 1, 2014).
10.1	364-Day Revolving Credit Agreement, dated as of September 30, 2014, among Enterprise Products Operating LLC, the Lenders party thereto, Citibank, N.A., as Administrative Agent, certain financial institutions from time to time named therein, as Co-Documentation Agents and Citibank, N.A. as Sole Lead Arranger and Sole Book Runner (incorporated by reference to Exhibit 10.1 to Form 8-K filed on October 1, 2014).
10.2	Guaranty Agreement, dated as of September 30, 2014, by Enterprise Products Partners L.P. in favor of Citibank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed on October 1, 2014).

10.3	Liquidity Option Agreement, dated as of October 1, 2014, between Enterprise Products Partners, L.P., Oiltanking Holding Americas, Inc., and Marquard & Bahls AG (incorporated by reference to Exhibit 10.3 to Form 8-K filed on October 1, 2014).
10.4	Seventh Amended and Restated Administrative Services Agreement, effective as of October 1, 2014, by and among Enterprise Products Operating LLC, EPCO Holdings, Inc., Enterprise Products Holdings LLC, Enterprise Products Partners L.P., Enterprise Products OLPGP, Inc., Enterprise Products Operating LLC, OTLP GP, LLC and Oiltanking Partners, L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed on October 21, 2014).
12.1#	Computation of ratio of earnings to fixed charges for the nine months ended September 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 nine months ended September 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 nine months ended September 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 nine months ended September 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 nine months ended September 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 November 10, 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

EXHIBIT 12.1

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

	For the Nine Months Ended September 30, 2014	For the Year Ended December 31, 2013	2012	2011	2010	2009
Consolidated income	$ 2,152.4	$ 2,607.1	$ 2,428.0	$ 2,088.3	$ 1,383.7	$ 1,140.3
Add: Provision for (benefit from) taxes	22.5	57.5	(17.2)	27.2	26.1	25.3
Less: Equity in earnings from unconsolidated affiliates	(179.1)	(167.3)	(64.3)	(46.4)	(62.0)	(92.3)
Consolidated pre-tax income before equity in earnings from unconsolidated affiliates	1,995.8	2,497.3	2,346.5	2,069.1	1,347.8	1,073.3
Add: Fixed charges	756.1	964.7	920.3	879.5	813.4	760.6
Amortization of capitalized interest	18.5	22.8	20.3	17.5	16.8	15.3
Distributed income of equity investees	260.7	251.6	116.7	156.4	191.9	169.3
Subtotal	3,031.1	3,736.4	3,403.8	3,122.5	2,369.9	2,018.5
Less: Capitalized interest	(53.4)	(133.0)	(116.8)	(106.7)	(47.2)	(53.1)
Net income attributable to noncontrolling interests	(24.8)	(10.2)	(8.1)	(20.5)	(25.5)	(26.4)
Total earnings	$ 2,952.9	$ 3,593.2	$ 3,278.9	$ 2,995.3	$ 2,297.2	$ 1,939.0
Fixed charges:						
Interest expense	$ 679.6	$ 802.5	$ 771.8	$ 744.1	$ 741.9	$ 687.3
Capitalized interest	53.4	133.0	116.8	106.7	47.2	53.1
Interest portion of rental expense	23.1	29.2	31.7	28.7	24.3	20.2
Total	$ 756.1	$ 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: November 10, 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.

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: November 10, 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 September 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: November 10, 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 September 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: November 10, 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.