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 March 31, 2016

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 2,081,508,834 common units of Enterprise Products Partners L.P. outstanding at the close of business on April 29, 2016. 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)

	March 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 160.6	$ 19.0
Restricted cash	136.9	15.9
Accounts receivable – trade, net of allowance for doubtful accounts of $11.9 at March 31, 2016 and $12.1 at December 31, 2015	2,449.4	2,569.9
Accounts receivable – related parties	1.1	1.2
Inventories	1,232.1	1,038.1
Derivative assets	234.9	258.6
Prepaid and other current assets	377.6	395.6
Total current assets	4,592.6	4,298.3
Property, plant and equipment, net	32,673.3	32,034.7
Investments in unconsolidated affiliates	2,684.1	2,628.5
Intangible assets, net of accumulated amortization of $1,282.1 at March 31, 2016 and $1,235.8 at December 31, 2015 (see Note 6)	3,990.9	4,037.2
Goodwill (see Note 6)	5,745.2	5,745.2
Other assets	51.3	58.3
Total assets	$ 49,737.4	$ 48,802.2
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 7)	$ 835.9	$ 1,863.9
Accounts payable – trade	743.5	860.1
Accounts payable – related parties	37.4	84.1
Accrued product payables	2,690.1	2,484.4
Accrued liability related to EFS Midstream acquisition	996.5	993.2
Accrued interest	193.9	352.1
Other current liabilities	516.1	528.8
Total current liabilities	6,013.4	7,166.6
Long-term debt (see Note 7)	21,919.8	20,676.9
Deferred tax liabilities	50.2	46.1
Other long-term liabilities	407.7	411.5
Commitments and contingencies (see Note 14)		
Equity:		
Partners' equity:		
Limited partners:		
Common units (2,055,907,178 units outstanding at March 31, 2016 and 2,012,553,024 units outstanding at December 31, 2015)	21,397.4	20,514.3
Accumulated other comprehensive loss	(268.5)	(219.2)
Total partners' equity	21,128.9	20,295.1
Noncontrolling interests	217.4	206.0
Total equity	21,346.3	20,501.1
Total liabilities and equity	$ 49,737.4	$ 48,802.2

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 March 31,	
	2016	2015
Revenues:		
Third parties	$ 4,989.7	$ 7,466.4
Related parties	15.6	6.1
Total revenues (see Note 9)	5,005.3	7,472.5
Costs and expenses:		
Operating costs and expenses:		
Third parties	3,866.3	6,384.3
Related parties	280.6	232.1
Total operating costs and expenses	4,146.9	6,616.4
General and administrative costs:		
Third parties	14.3	20.3
Related parties	29.6	29.0
Total general and administrative costs	43.9	49.3
Total costs and expenses (see Note 9)	4,190.8	6,665.7
Equity in income of unconsolidated affiliates	101.1	89.2
Operating income	915.6	896.0
Other income (expense):		
Interest expense	(240.6)	(239.1)
Other, net	3.6	0.5
Total other expense, net	(237.0)	(238.6)
Income before income taxes	678.6	657.4
Provision for income taxes	(8.4)	(6.8)
Net income	670.2	650.6
Net income attributable to noncontrolling interests (see Note 8)	(9.0)	(14.5)
Net income attributable to limited partners	$ 661.2	$ 636.1
Earnings per unit: (see Note 10)		
Basic earnings per unit	$ 0.32	$ 0.33
Diluted earnings per unit	$ 0.32	$ 0.32

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended March 31,	
	2016	**2015**
Net income	$ 670.2	$ 650.6
Other comprehensive income (loss):		
Cash flow hedges:		
Commodity derivative instruments:		
Changes in fair value of cash flow hedges	(1.2)	30.8
Reclassification of gains to net income	(57.2)	(61.1)
Interest rate derivative instruments:		
Reclassification of losses to net income	9.2	8.7
Total cash flow hedges	(49.2)	(21.6)
Other	(0.1)	--
Total other comprehensive loss	(49.3)	(21.6)
Comprehensive income	620.9	629.0
Comprehensive income attributable to noncontrolling interests	(9.0)	(14.5)
Comprehensive income attributable to limited partners	$ 611.9	$ 614.5

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 Three Months Ended March 31,	
	2016	**2015**
Operating activities:		
Net income	$ 670.2	$ 650.6
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	382.1	367.4
Non-cash asset impairment charges (see Note 12)	1.7	33.3
Equity in income of unconsolidated affiliates	(101.1)	(89.2)
Distributions received on earnings from unconsolidated affiliates	106.7	134.4
Net losses (gains) attributable to asset sales (see Note 15)	4.9	(0.1)
Deferred income tax expense	4.1	1.5
Changes in fair market value of derivative instruments	20.1	(4.6)
Net effect of changes in operating accounts (see Note 15)	(186.4)	(139.0)
Other operating activities	(2.6)	(0.3)
Net cash flows provided by operating activities	899.7	954.0
Investing activities:		
Capital expenditures	(1,007.2)	(812.8)
Contributions in aid of construction costs	12.2	19.6
Increase in restricted cash	(121.0)	(28.2)
Investments in unconsolidated affiliates	(70.4)	(68.3)
Distributions received for return of capital from unconsolidated affiliates	9.1	--
Proceeds from asset sales (see Note 15)	13.4	0.5
Other investing activities	--	0.1
Cash used in investing activities	(1,163.9)	(889.1)
Financing activities:		
Borrowings under debt agreements	20,000.6	9,182.5
Repayments of debt	(19,797.4)	(8,953.2)
Debt issuance costs	--	(0.1)
Cash distributions paid to limited partners (see Note 8)	(788.3)	(703.8)
Cash payments made in connection with distribution equivalent rights	(2.0)	(1.2)
Cash distributions paid to noncontrolling interests	(8.7)	(16.5)
Cash contributions from noncontrolling interests	11.1	4.0
Net cash proceeds from the issuance of common units	1,011.5	468.4
Other financing activities	(21.0)	(38.3)
Cash provided by (used in) financing activities	405.8	(58.2)
Net change in cash and cash equivalents	141.6	6.7
Cash and cash equivalents, January 1	19.0	74.4
Cash and cash equivalents, March 31	$ 160.6	$ 81.1

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
(See Note 8 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, 2015	$ 20,514.3	$ (219.2)	$ 206.0	$ 20,501.1
Net income	661.2	--	9.0	670.2
Cash distributions paid to limited partners	(788.3)	--	--	(788.3)
Cash payments made in connection with distribution equivalent rights	(2.0)	--	--	(2.0)
Cash distributions paid to noncontrolling interests	--	--	(8.7)	(8.7)
Cash contributions from noncontrolling interests	--	--	11.1	11.1
Net cash proceeds from the issuance of common units	1,011.5	--	--	1,011.5
Amortization of fair value of equity-based awards	22.3	--	--	22.3
Cash flow hedges	--	(49.2)	--	(49.2)
Other	(21.6)	(0.1)	--	(21.7)
Balance, March 31, 2016	$ 21,397.4	$ (268.5)	$ 217.4	$ 21,346.3

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2014	$ 18,304.8	$ (241.6)	$ 1,629.0	$ 19,692.2
Net income	636.1	--	14.5	650.6
Cash distributions paid to limited partners	(703.8)	--	--	(703.8)
Cash payments made in connection with distribution equivalent rights	(1.2)	--	--	(1.2)
Cash distributions paid to noncontrolling interests	--	--	(16.5)	(16.5)
Cash contributions from noncontrolling interests	--	--	4.0	4.0
Common units issued in connection with Step 2 of Oiltanking acquisition	1,408.7	--	(1,408.7)	--
Net cash proceeds from the issuance of common units	468.4	--	--	468.4
Amortization of fair value of equity-based awards	23.3	--	--	23.3
Cash flow hedges	--	(21.6)	--	(21.6)
Other	(37.4)	--	0.1	(37.3)
Balance, March 31, 2015	$ 20,098.9	$ (263.2)	$ 222.4	$ 20,058.1

See 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 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 Directors (the "Board") of Enterprise GP; (ii) Richard H. Bachmann, who is also a director and Vice Chairman of the Board of Enterprise GP; and (iii) Dr. Ralph S. Cunningham. Ms. Duncan Williams and Mr. Bachmann also currently serve as managers of Dan Duncan LLC along with W. Randall Fowler, who is also a director and President of Enterprise GP.

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 by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Duncan Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President and Chief Executive Officer of EPCO. Ms. Duncan Williams and Mr. Bachmann also currently serve as directors of EPCO along with Mr. Fowler, who is also the Executive Vice President and Chief Administrative Officer of EPCO. EPCO, together with its privately held affiliates, owned approximately 33.3% of our limited partner interests at March 31, 2016.

References to "Oiltanking" and "Oiltanking GP" mean Oiltanking Partners, L.P. and OTLP GP, LLC, the general partner of Oiltanking, respectively. In October 2014, we acquired approximately 65.9% of the limited partner interests of Oiltanking, all of the member interests of Oiltanking GP and the incentive distribution rights ("IDRs") held by Oiltanking GP from Oiltanking Holding Americas, Inc. ("OTA"), a U.S. corporation, as the first step of a two-step acquisition of Oiltanking. In February 2015, we completed the second step of this transaction consisting of the acquisition of the noncontrolling interests in Oiltanking.

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

References to "Offshore Business" refer to the Gulf of Mexico operations we sold to Genesis Energy, L.P. ("Genesis") in July 2015.

References to "EFS Midstream" mean EFS Midstream LLC, which we acquired in July 2015 from affiliates of Pioneer Natural Resources Company and Reliance Industries Limited.

Note 1. Partnership Operations, Organization and Basis of Presentation

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 liquid ("NGL") 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 the 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; 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. Our assets currently include approximately 49,000 miles of pipelines; 250 million barrels ("MMBbls") of storage capacity for NGLs, crude oil, petrochemicals and refined products; and 14 billion cubic feet ("Bcf") of natural gas storage capacity.

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. We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates under the collective common control of the DD LLC Trustees and the EPCO Trustees. 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 (the "ASA") or by other service providers. See Note 13 for information regarding the ASA and other related party matters.

Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & Services. On July 24, 2015, we completed the sale of our Offshore Business, which primarily consisted of our Offshore Pipelines & Services segment. Our consolidated financial statements reflect ownership of the Offshore Business through July 24, 2015. See Note 9 for additional information regarding our business segments.

As a result of our acquisition of the member interests of EFS Midstream effective July 1, 2015, we began consolidating the financial statements of EFS Midstream as of that date.

Effective January 1, 2016, we applied the provisions of Accounting Standard Update ("ASU") 2015-03, *Simplifying the Presentation of Debt Issuance Costs*, which requires bond issuance costs to be presented on the balance sheet as a deduction from the carrying value of the associated debt. The guidance was applied on a retrospective basis; therefore, we adjusted our December 31, 2015 consolidated balance sheet to reflect the reclassification of $14.7 million of bond issuance costs from prepaid and other current assets and $135.1 million from other assets to reduce the carrying amount of long-term debt by an aggregate $149.8 million. See Note 7 for additional information regarding our long-term debt.

Note 2. General Accounting and Disclosure Matters

Our results of operations for the three months ended March 31, 2016 are not necessarily indicative of results expected for the full year of 2016. 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, 2015 (the "2015 Form 10-K") filed with the SEC on February 26, 2016.

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 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.

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 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 12 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.

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.

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, NGLs, crude oil and refined products. Additional cash may be restricted to maintain our commodity derivative instruments portfolio as prices fluctuate or deposit requirements change. At March 31, 2016 and December 31, 2015, our restricted cash amounts were $136.9 million and $15.9 million, respectively. See Note 12 for information regarding our derivative instruments and hedging activities.

Note 3. Inventories

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

	March 31, 2016	December 31, 2015
NGLs	$ 625.8	$ 639.9
Petrochemicals and refined products	335.7	148.0
Crude oil	248.7	222.1
Natural gas	21.9	28.1
Total	$ 1,232.1	$ 1,038.1

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 March 31,	
	2016	2015
Cost of sales (1)	$ 3,208.3	$ 5,678.1
Lower of cost or market adjustments	5.3	3.5

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

Note 4. 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	March 31, 2016	December 31, 2015
Plants, pipelines and facilities (1)	3-45 (5)	$ 33,096.3	$ 32,525.0
Underground and other storage facilities (2)	5-40 (6)	3,147.1	3,000.5
Transportation equipment (3)	3-10	161.6	159.9
Marine vessels (4)	15-30	774.0	769.8
Land		262.7	262.7
Construction in progress		4,087.4	3,894.0
Total		41,529.1	40,611.9
Less accumulated depreciation		8,855.8	8,577.2
Property, plant and equipment, net		$ 32,673.3	$ 32,034.7

(1) Plants, pipelines and facilities include processing plants; NGL, natural gas, crude oil and petrochemical and refined products pipelines; terminal loading and unloading facilities; buildings; office furniture and equipment; 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) Transportation equipment includes tractor-trailer tank trucks and other vehicles and similar assets used in our operations.
(4) Marine vessels include tow boats, barges and related equipment used in our marine transportation business.
(5) 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; buildings, 20-40 years; office furniture and equipment, 3-20 years; and laboratory and shop equipment, 5-35 years.
(6) 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 March 31,	
	2016	2015
Depreciation expense (1)	$ 295.9	$ 291.3
Capitalized interest (2)	42.5	29.6

(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.

Asset Retirement Obligations

We record asset retirement obligations ("AROs") in connection with legal requirements to perform specified retirement activities under contractual arrangements and/or governmental regulations. Our contractual AROs primarily result from right-of-way agreements associated with our pipeline operations and real estate leases associated with our plant sites. In addition, we record AROs in connection with governmental regulations associated with the abandonment or retirement of above-ground brine storage pits and certain marine vessels. We also record AROs in connection with regulatory requirements associated with the renovation or demolition of certain assets containing hazardous substances such as asbestos. We typically fund our AROs using cash flow from operations.

Property, plant and equipment at March 31, 2016 and December 31, 2015 includes $17.5 million and $17.6 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents information regarding our AROs since December 31, 2015:

ARO liability balance, December 31, 2015	$	58.5
Liabilities settled		(1.5)
Revisions in estimated cash flows		1.7
Accretion expense		0.9
ARO liability balance, March 31, 2016	$	59.6

Note 5. 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 March 31, 2016	March 31, 2016	December 31, 2015
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 25.7	$ 25.9
K/D/S Promix, L.L.C.	50%	38.3	38.3
Baton Rouge Fractionators LLC	32.2%	17.9	18.5
Skelly-Belvieu Pipeline Company, L.L.C.	50%	39.1	39.8
Texas Express Pipeline LLC	35%	338.1	342.0
Texas Express Gathering LLC	45%	36.6	36.8
Front Range Pipeline LLC	33.3%	171.1	171.2
Delaware Basin Gas Processing LLC	50%	73.3	46.2
Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC	50%	1,420.0	1,396.0
Eagle Ford Pipeline LLC	50%	389.5	388.8
Eagle Ford Terminals Corpus Christi LLC	50%	39.1	28.6
Natural Gas Pipelines & Services:			
White River Hub, LLC	50%	22.3	22.5
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	5.3	5.4
Centennial Pipeline LLC	50%	64.6	65.6
Other	Various	3.2	2.9
Total		$ 2,684.1	$ 2,628.5

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

	For the Three Months Ended March 31, 2016	2015
NGL Pipelines & Services	$ 15.1	$ 11.6
Crude Oil Pipelines & Services	90.1	59.9
Natural Gas Pipelines & Services	1.0	0.9
Petrochemical & Refined Products Services	(5.1)	(3.4)
Offshore Pipelines & Services	--	20.2
Total	$ 101.1	$ 89.2

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

	March 31, 2016	December 31, 2015
NGL Pipelines & Services	$ 25.0	$ 25.3
Crude Oil Pipelines & Services	19.1	19.3
Petrochemical & Refined Products Services	2.3	2.3
Total	$ 46.4	$ 46.9

In total, amortization of excess cost amounts were $0.5 million and $2.6 million for the three months ended March 31, 2016 and 2015, respectively.

Summarized Combined Financial Information of Unconsolidated Affiliates

Combined results of operations data for the periods indicated for our unconsolidated affiliates are summarized in the following table (all data presented on a 100% basis):

	For the Three Months Ended March 31,	
	2016	2015
Income Statement Data:		
Revenues	$ 345.5	$ 349.5
Operating income	213.7	196.6
Net income	215.2	193.4

Note 6. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	March 31, 2016			December 31, 2015		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 447.4	$ (160.9)	$ 286.5	$ 447.4	$ (156.9)	$ 290.5
Contract-based intangibles	283.0	(197.0)	86.0	283.0	(193.2)	89.8
Segment total	730.4	(357.9)	372.5	730.4	(350.1)	380.3
Crude Oil Pipelines & Services:						
Customer relationship intangibles	2,204.4	(52.1)	2,152.3	2,204.4	(39.1)	2,165.3
Contract-based intangibles	281.4	(83.9)	197.5	281.4	(69.2)	212.2
Segment total	2,485.8	(136.0)	2,349.8	2,485.8	(108.3)	2,377.5
Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,350.3	(372.4)	977.9	1,350.3	(366.3)	984.0
Contract-based intangibles	464.7	(363.5)	101.2	464.7	(361.0)	103.7
Segment total	1,815.0	(735.9)	1,079.1	1,815.0	(727.3)	1,087.7
Petrochemical & Refined Products Services:						
Customer relationship intangibles	185.5	(39.7)	145.8	185.5	(38.3)	147.2
Contract-based intangibles	56.3	(12.6)	43.7	56.3	(11.8)	44.5
Segment total	241.8	(52.3)	189.5	241.8	(50.1)	191.7
Total intangible assets	$ 5,273.0	$ (1,282.1)	$ 3,990.9	$ 5,273.0	$ (1,235.8)	$ 4,037.2

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

	For the Three Months Ended March 31,	
	2016	2015
NGL Pipelines & Services	$ 7.8	$ 7.5
Crude Oil Pipelines & Services	27.7	16.7
Natural Gas Pipelines & Services	8.6	9.9
Petrochemical & Refined Products Services	2.2	2.4
Offshore Pipelines & Services	--	2.3
Total	$ 46.3	$ 38.8

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

Remainder of 2016	2017	2018	2019	2020
$ 133.3	$ 176.3	$ 171.7	$ 167.1	$ 166.4

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 since December 31, 2015:

	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Consolidated Total
Balance at December 31, 2015	$ 2,651.7	$ 1,841.0	$ 296.3	$ 956.2	$ 5,745.2
Balance at March 31, 2016	$ 2,651.7	$ 1,841.0	$ 296.3	$ 956.2	$ 5,745.2

Note 7. Debt Obligations

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

	March 31, 2016	December 31, 2015
EPO senior debt obligations:		
Commercial Paper Notes, variable-rates	$ 2,072.0	$ 1,114.1
Senior Notes AA, 3.20% fixed-rate, due February 2016	--	750.0
364-Day Credit Agreement, variable-rate, due September 2016	--	--
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
Senior Notes OO, 1.65% fixed-rate, due May 2018	750.0	750.0
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
Senior Notes LL, 2.55% fixed-rate, due October 2019	800.0	800.0
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
Multi-Year Revolving Credit Facility, variable-rate, due September 2020	--	--
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	850.0
Senior Notes MM, 3.75% fixed-rate, due February 2025	1,150.0	1,150.0
Senior Notes PP, 3.70% fixed-rate, due February 2026	875.0	875.0
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	1,400.0	1,400.0
Senior Notes KK, 5.10% fixed-rate, due February 2045	1,150.0	1,150.0
Senior Notes QQ, 4.90% fixed-rate, due May 2046	875.0	875.0
Senior Notes NN, 4.95% fixed-rate, due October 2054	400.0	400.0
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	21,472.0	21,264.1
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066 (1)	521.1	521.1
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 (2)	256.4	256.4
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068 (3)	682.7	682.7
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2
Total principal amount of senior and junior debt obligations	22,946.4	22,738.5
Other, non-principal amounts	(190.7)	(197.7)
Less current maturities of debt	(835.9)	(1,863.9)
Total long-term debt	$ 21,919.8	$ 20,676.9

(1) Fixed rate of 8.375% through August 1, 2016 (i.e., first call date without a make-whole redemption premium); thereafter, variable rate based on 3-month LIBOR plus 3.708%.
(2) Fixed rate of 7.000% through September 1, 2017 (i.e., first call date without a make-whole redemption premium); thereafter, variable rate based on 3-month LIBOR plus 2.778%.
(3) Fixed rate of 7.034% through January 15, 2018 (i.e., first call date without a make-whole redemption premium); thereafter, the rate will be the greater of 7.034% or a variable rate based on 3-month LIBOR plus 2.680%.

At December 31, 2015, we reclassified $149.8 million of bond issuance costs, which were previously accounted for as assets on our consolidated balance sheet, to long-term debt in connection with the adoption of ASU 2015-03 (see Note 1). These amounts are a component of “Other, non-principal amounts” in the preceding table.

The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at March 31, 2016 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt					
	Total	Remainder of 2016	2017	2018	2019	2020	Thereafter
Commercial Paper Notes	$ 2,072.0	$ 2,072.0	$ --	$ --	$ --	$ --	$ --
Senior Notes	19,400.0	--	800.0	1,100.0	1,500.0	1,500.0	14,500.0
Junior Subordinated Notes	1,474.4	--	--	--	--	--	1,474.4
Total	$ 22,946.4	$ 2,072.0	$ 800.0	$ 1,100.0	$ 1,500.0	$ 1,500.0	$ 15,974.4

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 $1.25 Billion of Senior Notes in April 2016
In April 2016, EPO issued $575 million in principal amount of 2.85% senior notes due April 2021 ("Senior Notes RR"), $575 million in principal amount of 3.95% senior notes due February 2027 ("Senior Notes SS") and $100 million in principal amount of 4.90% reopened senior notes due May 2046 ("Senior Notes QQ"). Senior Notes RR, SS and QQ were issued at 99.898%, 99.760% and 95.516% of their principal amounts, respectively. We issued these senior notes using our 2013 Shelf (see Note 8).

Net proceeds from the issuance of these senior notes were used as follows: (i) the repayment of amounts then outstanding under EPO's commercial paper program, which included amounts we used to repay $750 million in principal amount of Senior Notes AA that matured in February 2016, and (ii) 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 an indenture 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.

Letters of Credit
At March 31, 2016, 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 March 31, 2016.

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 three months ended March 31, 2016:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
Commercial Paper Notes	0.56% to 1.18%	0.89%
Multi-Year Revolving Credit Facility	1.43% to 1.43%	1.43%

Note 8. Equity and Distributions

Partners Equity

Partners' equity reflects the limited partner interests (i.e., common units, including restricted common units) that we have outstanding. The following table summarizes changes in the number of our outstanding units from December 31, 2015 to March 31, 2016:

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
Number of units outstanding at December 31, 2015	2,010,592,504	1,960,520	2,012,553,024
Common units issued in connection with ATM program	35,396,147	--	35,396,147
Common units issued in connection with DRIP and EUPP	7,282,006	--	7,282,006
Common units issued in connection with the vesting of phantom unit awards	1,053,117	--	1,053,117
Common units issued in connection with the vesting of restricted common unit awards	1,167,578	(1,167,578)	--
Forfeiture of restricted common unit awards	--	(9,350)	(9,350)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(388,396)	--	(388,396)
Other	20,630	--	20,630
Number of units outstanding at March 31, 2016	2,055,123,586	783,592	2,055,907,178

The net cash proceeds we received from the issuance of common units during the three months ended March 31, 2016 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and revolving credit facilities and for general company purposes.

Universal shelf registration statement

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 (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. See Note 7 for information regarding an offering of senior notes we completed in April 2016 using the 2013 Shelf.

The 2013 Shelf will expire in June 2016, at which time we expect to file a replacement universal shelf registration statement.

ATM program

We have a registration statement on file with the SEC in connection with our "at-the-market" program (or "ATM program"). Pursuant to this 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 three months ended March 31, 2016, we sold 35,396,147 common units under the ATM program for aggregate gross proceeds of $856.5 million. This includes 3,830,256 common units sold in January 2016 to privately held affiliates of EPCO, which generated gross proceeds of $100 million. After taking into account applicable costs, our transactions under the ATM program resulted in aggregate net cash proceeds of $849.0 million during the three months ended March 31, 2016. During the three months ended March 31, 2015, we issued 12,350,761 common units under this program for aggregate gross cash proceeds of $407.8 million, resulting in total net cash proceeds of $404.2 million.

During the period April 1, 2016 through April 8, 2016, we sold an additional 25,550,931 common units under the ATM program for aggregate gross proceeds of $594.1 million, resulting in net cash proceeds of $592.0 million. After taking into account the aggregate sales price of common units sold under our ATM program through April 8, 2016, our capacity under the applicable registration statement was reduced to $415.7 million. On April 22, 2016, we filed a registration statement with the SEC that (when declared effective) will replace our existing registration statement with respect to the ATM program and increase the available capacity under the ATM program to allow us to issue up to an aggregate $2.17 billion of additional common units, inclusive of the remaining capacity under such existing registration statement.

Distribution reinvestment plan

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 ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of our common units they own by reinvesting the quarterly cash distributions they receive from us into the purchase of additional new common units. We issued a total of 7,162,744 common units under our DRIP during the three months ended March 31, 2016, which generated net cash proceeds of $159.8 million. During the three months ended March 31, 2015, we issued 1,869,079 common units under our DRIP, which generated net cash proceeds of $61.7 million. Privately held affiliates of EPCO reinvested $100 million through the DRIP during the three months ended March 31, 2016 (this amount being a component of the net cash proceeds presented). After taking into account the number of common units issued under the DRIP through March 31, 2016, we have the capacity to issue an additional 7,905,254 common units under this plan. We expect to file a new registration statement during the second quarter of 2016 to increase the number of common units available for issuance under the DRIP.

Employee unit purchase plan

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 our employee unit purchase plan ("EUPP"). We issued 119,262 common units under our EUPP during the three months ended March 31, 2016, which generated net cash proceeds of $2.7 million. During the three months ended March 31, 2015, we issued 71,753 common units under our EUPP, which generated net cash proceeds of $2.5 million. After taking into account the number of common units issued under the EUPP through March 31, 2016, we may issue an additional 6,653,244 common units under this plan.

Noncontrolling Interests

Noncontrolling interests represent third party equity ownership interests in our consolidated subsidiaries.

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, 2015	$ 56.6	$ (279.5)	$ 3.7	$ (219.2)
Other comprehensive loss before reclassifications	(1.2)	--	(0.1)	(1.3)
Amounts reclassified from accumulated other comprehensive loss (income)	(57.2)	9.2	--	(48.0)
Total other comprehensive income (loss)	(58.4)	9.2	(0.1)	(49.3)
Balance, March 31, 2016	$ (1.8)	$ (270.3)	$ 3.6	$ (268.5)

	Gains (Losses) on Cash Flow Hedges			
	Commodity Derivative Instruments	Interest Rate Derivative Instruments	Other	Total
Balance, December 31, 2014	$ 69.9	$ (314.8)	$ 3.3	$ (241.6)
Other comprehensive income before reclassifications	30.8	--	--	30.8
Amounts reclassified from accumulated other comprehensive loss (income)	(61.1)	8.7	--	(52.4)
Total other comprehensive income (loss)	(30.3)	8.7	--	(21.6)
Balance, March 31, 2015	$ 39.6	$ (306.1)	$ 3.3	$ (263.2)

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

		For the Three Months Ended March 31,	
	Location	2016	2015
Losses (gains) on cash flow hedges:			
Interest rate derivatives	Interest expense	$ 9.2	$ 8.7
Commodity derivatives	Revenue	(58.8)	(61.1)
Commodity derivatives	Operating costs and expenses	1.6	--
Total		$ (48.0)	$ (52.4)

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
2015:			
1st Quarter	$ 0.3750	4/30/2015	5/7/2015
2016:			
1st Quarter	$ 0.3950	4/29/2016	5/6/2016

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 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 to partners during 2015 excluded 35,380,000 Designated Units. The temporary distribution waiver expired in November 2015; therefore, distributions to be paid, if any, during calendar year 2016 will include all common units owned by the privately held affiliates of EPCO.

Note 9. Business Segments

Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & 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.

Our consolidated financial statements reflect ownership of the Offshore Business through July 24, 2015, which was the closing date of the sales transaction.

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.

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 (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 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 remainder of our consolidated total assets, which consist primarily of working capital assets, are excluded from segment assets since these amounts are not attributable to one specific segment (e.g. cash).

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

	For the Three Months Ended March 31,	
	2016	2015
Revenues	$ 5,005.3	$ 7,472.5
Subtract operating costs and expenses	(4,146.9)	(6,616.4)
Add equity in income of unconsolidated affiliates	101.1	89.2
Add depreciation, amortization and accretion expense amounts not reflected in gross operating margin	358.2	345.3
Add impairment charges not reflected in gross operating margin	1.7	33.3
Add net losses or subtract net gains attributable to asset sales not reflected in gross operating margin	4.9	(0.1)
Add non-refundable deferred revenues attributable to shipper make-up rights on major new pipeline projects reflected in gross operating margin	7.1	30.7
Subtract subsequent recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	(12.9)	(20.1)
Total segment gross operating margin	$ 1,318.5	$ 1,334.4

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 March 31,	
	2016	2015
Total segment gross operating margin	$ 1,318.5	$ 1,334.4
Adjustments to reconcile total segment gross operating margin to operating income:		
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(358.2)	(345.3)
Subtract impairment charges not reflected in gross operating margin	(1.7)	(33.3)
Add net gains or subtract net losses attributable to asset sales not reflected in gross operating margin	(4.9)	0.1
Subtract non-refundable deferred revenues attributable to shipper make-up rights on major new pipeline projects reflected in gross operating margin	(7.1)	(30.7)
Add subsequent recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	12.9	20.1
Subtract general and administrative costs not reflected in gross operating margin	(43.9)	(49.3)
Operating income	915.6	896.0
Other expense, net	(237.0)	(238.6)
Income before income taxes	$ 678.6	$ 657.4

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

	Reportable Business Segments						
	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Offshore Pipelines & Services	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:							
Three months ended March 31, 2016	$ 2,402.0	$ 1,277.5	$ 547.3	$ 762.9	$ --	$ --	$ 4,989.7
Three months ended March 31, 2015	2,674.8	2,677.0	730.9	1,349.1	34.6	--	7,466.4
Revenues from related parties:							
Three months ended March 31, 2016	1.8	11.1	2.7	--	--	--	15.6
Three months ended March 31, 2015	1.5	1.0	3.0	--	0.6	--	6.1
Intersegment and intrasegment revenues:							
Three months ended March 31, 2016	3,174.8	1,499.4	124.7	242.7	--	(5,041.6)	--
Three months ended March 31, 2015	2,443.1	1,277.1	170.0	285.6	0.4	(4,176.2)	--
Total revenues:							
Three months ended March 31, 2016	5,578.6	2,788.0	674.7	1,005.6	--	(5,041.6)	5,005.3
Three months ended March 31, 2015	5,119.4	3,955.1	903.9	1,634.7	35.6	(4,176.2)	7,472.5
Equity in income (loss) of unconsolidated affiliates:							
Three months ended March 31, 2016	15.1	90.1	1.0	(5.1)	--	--	101.1
Three months ended March 31, 2015	11.6	59.9	0.9	(3.4)	20.2	--	89.2
Gross operating margin:							
Three months ended March 31, 2016	783.7	202.3	177.7	154.8	--	--	1,318.5
Three months ended March 31, 2015	695.2	214.0	204.5	174.6	46.1	--	1,334.4
Property, plant and equipment, net: (see Note 4)							
At March 31, 2016	12,934.9	3,896.6	8,551.1	3,203.3	--	4,087.4	32,673.3
At December 31, 2015	12,909.7	3,550.3	8,620.0	3,060.7	--	3,894.0	32,034.7
Investments in unconsolidated affiliates: (see Note 5)							
At March 31, 2016	740.1	1,848.6	22.3	73.1	--	--	2,684.1
At December 31, 2015	718.7	1,813.4	22.5	73.9	--	--	2,628.5
Intangible assets, net: (see Note 6)							
At March 31, 2016	372.5	2,349.8	1,079.1	189.5	--	--	3,990.9
At December 31, 2015	380.3	2,377.5	1,087.7	191.7	--	--	4,037.2
Goodwill: (see Note 6)							
At March 31, 2016	2,651.7	1,841.0	296.3	956.2	--	--	5,745.2
At December 31, 2015	2,651.7	1,841.0	296.3	956.2	--	--	5,745.2
Segment assets:							
At March 31, 2016	16,699.2	9,936.0	9,948.8	4,422.1	--	4,087.4	45,093.5
At December 31, 2015	16,660.4	9,582.2	10,026.5	4,282.5	--	3,894.0	44,445.6

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

	For the Three Months Ended March 31,	
	2016	2015
NGL Pipelines & Services:		
Sales of NGLs and related products	$ 1,943.5	$ 2,242.2
Midstream services	460.3	434.1
Total	2,403.8	2,676.3
Crude Oil Pipelines & Services:		
Sales of crude oil	1,121.1	2,570.7
Midstream services	167.5	107.3
Total	1,288.6	2,678.0
Natural Gas Pipelines & Services:		
Sales of natural gas	315.0	476.3
Midstream services	235.0	257.6
Total	550.0	733.9
Petrochemical & Refined Products Services:		
Sales of petrochemicals and refined products	553.2	1,151.0
Midstream services	209.7	198.1
Total	762.9	1,349.1
Offshore Pipelines & Services:		
Sales of crude oil	--	1.1
Midstream services	--	34.1
Total	--	35.2
Total consolidated revenues	$ 5,005.3	$ 7,472.5
Consolidated costs and expenses		
Operating costs and expenses:		
Cost of sales	$ 3,208.3	$ 5,678.1
Other operating costs and expenses (1)	573.8	559.8
Depreciation, amortization and accretion	358.2	345.3
Net losses (gains) attributable to asset sales	4.9	(0.1)
Non-cash asset impairment charges	1.7	33.3
General and administrative costs	43.9	49.3
Total consolidated costs and expenses	$ 4,190.8	$ 6,665.7

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

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 10. 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 March 31, 2016	For the Three Months Ended March 31, 2015
BASIC EARNINGS PER UNIT		
Net income attributable to limited partners	$ 661.2	$ 636.1
Undistributed earnings allocated and cash payments on phantom unit awards (1)	(3.2)	(2.2)
Net income available to common unitholders	$ 658.0	$ 633.9
Basic weighted-average number of common units outstanding	2,033.6	1,926.4
Basic earnings per unit	$ 0.32	$ 0.33
DILUTED EARNINGS PER UNIT		
Net income attributable to limited partners	$ 661.2	$ 636.1
Diluted weighted-average number of units outstanding:		
Distribution-bearing common units	2,033.6	1,926.4
Designated Units	--	35.4
Phantom units (1)	6.9	4.5
Incremental option units	--	0.4
Total	2,040.5	1,966.7
Diluted earnings per unit	$ 0.32	$ 0.32

(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 our 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.

Note 11. 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 March 31, 2016	For the Three Months Ended March 31, 2015
Equity-classified awards:		
Phantom unit awards	$ 19.4	$ 17.2
Restricted common unit awards	2.2	6.1
Profits interests awards	0.7	--
Liability-classified awards	0.1	0.1
Total	$ 22.4	$ 23.4

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 March 31, 2016, 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 35,000,000 at March 31, 2016. This amount will automatically increase under the terms of the 2008 Plan by 5,000,000 common units on January 1, 2017 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 March 31, 2016, a total of 3,245,652 and 17,981,493 additional common units were available for issuance under these plans, respectively.

In addition, in February 2016, EPCO formed three limited partnerships (generally referred to as "Employee Partnerships") to serve as incentive arrangements for key employees of EPCO by providing them a "profits interest" in an Employee Partnership. The names of the Employee Partnerships are EPD PubCo Unit I L.P. ("EPD PubCo I"), EPD PubCo Unit II L.P. ("EPD PubCo II") and EPD PrivCo Unit I L.P. ("EPD PrivCo I"). The Employee Partnerships are discussed later in this note.

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 March 31, 2016, 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. The grant date fair value of a phantom unit award is based on the market price per unit of our common units on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

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, 2015	5,426,949	$ 33.63
Granted (2)	4,467,730	$ 21.86
Vested	(1,586,493)	$ 33.56
Forfeited	(41,673)	$ 31.11
Phantom unit awards at March 31, 2016	8,266,513	$ 27.29

(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 2016 was $97.7 million based on a grant date market price of our common units of $21.86 per unit. An estimated annual forfeiture rate of 3.9% 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 to our 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 phantom unit awards for the periods indicated:

	For the Three Months Ended March 31, 2016	2015
Cash payments made in connection with DERs	$ 2.0	$ 1.2
Total intrinsic value of phantom unit awards that vested during period	$ 36.3	$ 26.6

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was $145.2 million at March 31, 2016, of which our share of the cost is currently estimated to be $133.1 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.

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 fair value of a restricted common unit award is based on the market price per unit of our common units on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

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

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted common units at December 31, 2015	1,960,520	$ 27.88
Vested	(1,167,578)	$ 27.39
Forfeited	(9,350)	$ 28.32
Restricted common units at March 31, 2016	783,592	$ 28.60

(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 to our 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 restricted common unit awards for the periods indicated:

	For the Three Months Ended March 31, 2016	2015
Cash distributions paid to restricted common unitholders	$ 0.8	$ 1.5
Total intrinsic value of restricted common unit awards that vested during period	$ 26.8	$ 62.4

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $4.7 million at March 31, 2016, of which our share of the cost is currently estimated to be $3.5 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 approximately one year.

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options denominated in our common units. All of our unit option awards had been exercised as of December 31, 2015 and no new unit option awards were granted during the three months ended March 31, 2016.

In order to fund its unit option award-related obligations, EPCO purchased our common units at fair value 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 three months ended March 31, 2015:

Total intrinsic value of unit option awards exercised during period	$	17.4
Cash received from EPCO in connection with the exercise of unit option awards		10.1
Unit option award-related cash reimbursements to EPCO		17.4

Profits Interest Awards

On February 22, 2016, EPCO Holdings Inc. ("EPCO Holdings"), a privately held affiliate of EPCO, contributed the following Enterprise common units it owned to the Employee Partnerships: (i) 2,723,052 units to EPD PubCo I, (ii) 2,834,198 units to EPD PubCo II and (iii) 1,111,438 units to EPD PrivCo I. In exchange for these contributions, EPCO Holdings was admitted as the Class A limited partner of each Employee Partnership. Also on the contribution date, certain key EPCO employees were issued Class B limited partner interests (i.e., profits interest awards) and admitted as Class B limited partners of each Employee Partnership, all without any capital contribution by such employees. EPCO serves as the general partner of each Employee Partnership.

In general, the Class A limited partner earns a preferred return (the "Class A Preference Return," as described below) on its investment (or "Capital Base") in each Employee Partnership, with any residual cash amounts being paid to the Class B limited partners of such Employee Partnership on a quarterly basis. Upon liquidation of an Employee Partnership, assets having a then current fair market value equal to the Class A limited partner's Capital Base in such Employee Partnership, plus any preferred return for the period in which liquidation occurs, will be distributed to the Class A limited partner. Any remaining assets of such Employee Partnership will be distributed to the Class B limited partners of such Employee Partnership as a residual profits interest, which represents the appreciation in value of the Employee Partnership's assets since the date of EPCO Holdings' contribution to it, as described above.

Unless otherwise agreed to by EPCO and a majority in interest of the limited partners of each Employee Partnership, such Employee Partnership will terminate at the earliest to occur of (i) 30 days following its vesting date, (ii) a change of control or (iii) a dissolution of the Employee Partnership. Class B limited partner interests in EPD PubCo I vest four years from February 22, 2016, and Class B limited partner interests in EPD PubCo II and EPD PrivCo I vest five years from that date.

Individually, each Class B limited partner interest is subject to forfeiture if the participating employee's employment with EPCO is terminated prior to vesting, with customary exceptions for death, disability and certain retirements. The risk of forfeiture will also lapse upon certain change of control events. Forfeited individual Class B limited partner interests are allocated to the remaining Class B limited partners.

The following table summarizes key elements of each Employee Partnership:

Employee Partnership	Enterprise Common Units owned by Employee Partnership	Class A Capital Base (1)	Class A Partner Preferred Return Rate (2)	Expected Liquidation Date	Estimated Grant Date Fair Value of Profits Interest Awards (3)	Unrecognized Compensation Cost (4)
EPD PubCo I	2,723,052 units	$63.5 million	6.6638%	Feb. 2020	$13.2 million	$12.7 million
EPD PubCo II	2,834,198 units	$66.1 million	6.6638%	Feb. 2021	$14.8 million	$14.3 million
EPD PrivCo I	1,111,438 units	$25.9 million	6.6638%	Feb. 2021	$5.8 million	$1.2 million

(1) Represents the fair market value of the Enterprise common units contributed at the contribution date.
(2) For each period, the Class A Preference Return equals the Class A Capital Base, after adjusting for certain retained cash distributions and other amounts as defined in the underlying agreements, multiplied by 6.6638% divided by 365 or 366 days, as the case may be during such calendar year, multiplied by the number of days in the applicable period.
(3) Represents the total grant date fair value of the profits interest awards irrespective of how such costs will be allocated between us and EPCO and its privately held affiliates.
(4) Represents our expected share of the unrecognized compensation cost at March 31, 2016. We expect to recognize our share of the unrecognized compensation cost for EPD PubCo I, EPD PubCo II and EPD PrivCo I over a weighted-average period of 3.9 years, 4.9 years and 4.9 years, respectively.

The grant date fair value of each Employee Partnership is based on (i) the estimated value (as determined using a Black-Scholes option pricing model) of such Employee Partnership's assets that would be distributed to the Class B limited partners thereof upon liquidation and (ii) the value, based on a discounted cash flow analysis, of the residual quarterly cash amounts that such Class B limited partners are expected to receive over the life of the Employee Partnership.

The following table summarizes the assumptions we used in applying a Black-Scholes option pricing model to derive that portion of the estimated grant date fair value of the profits interest awards for each Employee Partnership:

Employee Partnership	Expected Life of Award	Risk-Free Interest Rate	Expected Distribution Yield	Expected Unit Price Volatility
EPD PubCo I	4.0 years	1.09%	6.68%	40%
EPD PubCo II	5.0 years	1.25%	6.68%	40%
EPD PrivCo I	5.0 years	1.25%	6.68%	40%

Compensation expense attributable to the profits interest awards is based on the estimated grant date fair value of each award. A portion of the fair value of these equity-based awards is allocated to us under the ASA as a non-cash expense. We are not responsible for reimbursing EPCO for any expenses of the Employee Partnerships, including the value of any contributions of units made by EPCO Holdings.

Note 12. 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. This strategy may be used in controlling our overall cost of capital associated with such borrowings. The following table summarizes our portfolio of interest rate swaps at March 31, 2016:

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes OO	10 fixed-to-floating swaps	$750.0	5/2015 to 5/2018	1.65% to 1.10%	Fair value hedge

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, petrochemicals and refined 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 March 31, 2016 (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)	32.7	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	6.5	n/a	Cash flow hedge
Octane enhancement:			
Forecasted sales of octane enhancement products (MMBbls)	1.0	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	7.2	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	8.9	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	58.3	0.5	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	66.3	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	1.8	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.5	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	5.1	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	13.1	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	20.3	n/a	Cash flow hedge
Crude oil inventory management activities (MMBbls)	0.2	n/a	Fair value hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (4,5)	80.9	7.4	Mark-to-market
NGL risk management activities (MMBbls) (5)	4.0	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	28.5	2.3	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 2017, December 2016 and March 2019, 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 51.0 Bcf and 2.1 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 March 31, 2016, 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 natural gas processing margins and (iii) hedging the fair value of commodity products held in inventory.

- The objective of our anticipated future commodity purchases and sales hedging program is to hedge the margins of certain transportation, storage, blending and operational activities by locking in purchase and sale prices 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 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.

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			
	March 31, 2016		December 31, 2015		March 31, 2016		December 31, 2015	
	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	Current assets	$ 5.2	Current assets	$ 3.2	Other current liabilities	$ --	Other current liabilities	$ --
Interest rate derivatives	Other assets	1.6	Other assets	--	Other liabilities	--	Other liabilities	3.7
Total interest rate derivatives		6.8		3.2		--		3.7
Commodity derivatives	Current assets	153.1	Current assets	253.8	Other current liabilities	220.8	Other current liabilities	137.5
Commodity derivatives	Other assets	0.6	Other assets	0.2	Other liabilities	0.3	Other liabilities	1.4
Total commodity derivatives		153.7		254.0		221.1		138.9
Total derivatives designated as hedging instruments		$ 160.5		$ 257.2		$ 221.1		$ 142.6
Derivatives not designated as hedging instruments								
Commodity derivatives	Current assets	$ 76.6	Current assets	$ 1.6	Other current liabilities	$ 66.3	Other current liabilities	$ 3.1
Commodity derivatives	Other assets	0.7	Other assets	--	Other liabilities	1.8	Other liabilities	1.0
Total commodity derivatives		$ 77.3		$ 1.6		$ 68.1		$ 4.1

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 of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet: Financial Instruments	Cash Collateral Received	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)			(v) = (iii) + (iv)
As of March 31, 2016:							
Interest rate derivatives	$ 6.8	$ --	$ 6.8	$ --	$ --	$ --	$ 6.8
Commodity derivatives	231.0	--	231.0	(228.9)	--	--	2.1
As of December 31, 2015:							
Interest rate derivatives	$ 3.2	$ --	$ 3.2	$ (3.2)	$ --	$ --	$ --
Commodity derivatives	255.6	--	255.6	(143.0)	(40.1)	(72.2)	0.3

Offsetting of Financial Liabilities and Derivative Liabilities

	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet: Financial Instruments	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)		(v) = (iii) + (iv)
As of March 31, 2016:						
Commodity derivatives	$ 289.2	$ --	$ 289.2	$ (228.9)	$ (59.0)	$ 1.3
As of December 31, 2015:						
Interest rate derivatives	$ 3.7	$ --	$ 3.7	$ (3.2)	$ --	$ 0.5
Commodity derivatives	143.0	--	143.0	(143.0)	--	--

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 these tables, 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 these tables.

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 March 31, 2016	2015
Interest rate derivatives	Interest expense	$ 6.1	$ --
Commodity derivatives	Revenue	(19.0)	0.7
Total		$ (12.9)	$ 0.7

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item — For the Three Months Ended March 31, 2016	2015
Interest rate derivatives	Interest expense	$ (6.2)	$ --
Commodity derivatives	Revenue	28.0	8.6
Total		$ 21.8	$ 8.6

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 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 March 31,	
	2016	2015
Commodity derivatives – Revenue (1)	$ 3.3	$ 32.6
Commodity derivatives – Operating costs and expenses (1)	(4.5)	(1.8)
Total	$ (1.2)	$ 30.8

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

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) to Income (Effective Portion)	
		For the Three Months Ended March 31,	
		2016	2015
Interest rate derivatives	Interest expense	$ (9.2)	$ (8.7)
Commodity derivatives	Revenue	58.8	61.1
Commodity derivatives	Operating costs and expenses	(1.6)	--
Total		$ 48.0	$ 52.4

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)	
		For the Three Months Ended March 31,	
		2016	2015
Commodity derivatives	Revenue	$ --	$ 0.3

Over the next twelve months, we expect to reclassify $37.9 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 $1.9 million of net losses attributable to commodity derivative instruments from accumulated other comprehensive income to earnings, $0.6 million as an increase in revenue and $2.5 million as an increase 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 March 31,	
		2016	2015
Commodity derivatives	Revenue	$ (1.3)	$ (0.4)
Commodity derivatives	Operating costs and expenses	0.1	--
Total		$ (1.2)	$ (0.4)

Fair Value Measurements

The following tables set forth, by level within the Level 1, 2 and 3 fair value hierarchy, the carrying values of our financial assets and liabilities at the dates indicated. 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.

	March 31, 2016 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	$ --	$ 6.8	$ --	$ 6.8
Commodity derivatives	114.8	113.9	2.3	231.0
Total	$ 114.8	$ 120.7	$ 2.3	$ 237.8
Financial liabilities:				
Liquidity Option Agreement	$ --	$ --	$ 242.9	$ 242.9
Commodity derivatives	126.6	160.9	1.7	289.2
Total	$ 126.6	$ 160.9	$ 244.6	$ 532.1

	December 31, 2015 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	$ --	$ 3.2	$ --	$ 3.2
Commodity derivatives	109.5	145.2	0.9	255.6
Total	$ 109.5	$ 148.4	$ 0.9	$ 258.8
Financial liabilities:				
Liquidity Option Agreement	$ --	$ --	$ 245.1	$ 245.1
Interest rate derivatives	--	3.7	--	3.7
Commodity derivatives	31.3	109.2	2.5	143.0
Total	$ 31.3	$ 112.9	$ 247.6	$ 391.8

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:

		For the Three Months Ended March 31,	
	Location	**2016**	**2015**
Financial liability balance, net, January 1		$ (246.7)	$ (219.3)
Total gains (losses) included in:			
Net income (1)	Revenue	0.7	(0.4)
Net income	Other expense, net	2.2	--
Other comprehensive income (loss)	Commodity derivative instruments – changes in fair value of cash flow hedges	1.5	(1.5)
Settlements		(0.1)	(0.5)
Transfers out of Level 3		0.1	0.1
Financial liability balance, net, March 31		$ (242.3)	$ (221.6)

(1) There were $0.6 million of unrealized gains and $1.0 million of unrealized losses included in these amounts for the three months ended March 31, 2016 and 2015, respectively.

The following table provides quantitative information regarding our recurring Level 3 fair value measurements for commodity derivatives at March 31, 2016:

	Fair Value				
	Financial Assets	Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Crude oil	$ 1.6	$ 1.4	Discounted cash flow	Forward commodity prices	$36.30-$43.03/barrel
Commodity derivatives – Propane	--	0.3	Discounted cash flow	Forward commodity prices	$0.91-$0.93/gallon
Commodity derivatives – Natural gasoline	0.7	--	Discounted cash flow	Forward commodity prices	$0.48/gallon
Total	$ 2.3	$ 1.7			

With respect to commodity derivatives, we believe forward commodity prices are the most significant unobservable inputs in determining our Level 3 recurring fair value measurements at March 31, 2016. 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 the periods indicated:

	For the Three Months Ended March 31,	
	2016	2015
NGL Pipelines & Services	$ 0.4	$ 0.8
Crude Oil Pipelines & Services	0.2	7.8
Natural Gas Pipelines & Services	--	20.7
Petrochemical & Refined Products Services	1.1	0.4
Offshore Pipelines & Services	--	3.6
Total	$ 1.7	$ 33.3

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

Our non-cash impairment charges for the three months ended March 31, 2016 include $1.1 million related to other current assets, primarily spare parts and materials. The following table presents categories of long-lived assets, primarily property, plant and equipment, that were subject to non-recurring fair value measurements during the three months ended March 31, 2016:

		Fair Value Measurements at the End of the Reporting Period Using			
	Carrying Value at March 31, 2016	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
Long-lived assets disposed of other than by sale	$ --	$ --	$ --	$ --	$ 0.6

The following table presents categories of long-lived assets, primarily property, plant and equipment, that were subject to non-recurring fair value measurements during the three months ended March 31, 2015:

		Fair Value Measurements at the End of the Reporting Period Using			
	Carrying Value at March 31, 2015	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
Long-lived assets disposed of other than by sale	$ --	$ --	$ --	$ --	$ 33.1
Long-lived assets held for sale	0.6	--	--	0.6	0.2
Total					$ 33.3

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 $20.27 billion and $19.51 billion at March 31, 2016 and December 31, 2015, respectively. The aggregate carrying value of these debt obligations was $20.12 billion and $20.87 billion at March 31, 2016 and December 31, 2015, 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 amounts reported for fixed-rate debt obligations exclude those amounts hedged using fixed-to-floating interest rate swaps. See "*Interest Rate Hedging Activities*" within this Note 12 for additional information. 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 13. Related Party Transactions

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

	For the Three Months Ended March 31,	
	2016	2015
Revenues – related parties:		
Unconsolidated affiliates	$ 15.6	$ 6.1
Costs and expenses – related parties:		
EPCO and its privately held affiliates	$ 237.3	$ 221.9
Unconsolidated affiliates	72.9	39.2
Total	$ 310.2	$ 261.1

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

	March 31, 2016	December 31, 2015
Accounts receivable - related parties:		
Unconsolidated affiliates	$ 1.1	$ 1.2
Accounts payable - related parties:		
EPCO and its privately held affiliates	$ 24.3	$ 75.6
Unconsolidated affiliates	13.1	8.5
Total	$ 37.4	$ 84.1

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 March 31, 2016, EPCO and its privately held affiliates (including Dan Duncan LLC and certain Duncan family trusts) beneficially owned the following limited partner interests in us:

Total Number of Units	Percentage of Total Units Outstanding
685,481,428	33.3%

Of the total number of units held by EPCO and its privately held affiliates, 118,000,000 have been pledged as security under the credit facilities of certain of the privately held affiliates at March 31, 2016. These credit facilities contain customary and other events of default, including defaults by us and other affiliates of EPCO. An event of default, followed by a foreclosure on the pledged collateral, could ultimately result in a change in ownership of these units and affect the market price of our common units.

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 three months ended March 31, 2016 and 2015, we paid EPCO and its privately held affiliates cash distributions totaling $260.1 million and $231.2 million, respectively. Distributions paid during 2015 excluded 35,380,000 Designated Units (see Note 8).

In January 2016, privately held affiliates of EPCO purchased 3,830,256 common units from us under our ATM program, generating gross proceeds of $100 million. In February 2016, privately held affiliates of EPCO reinvested $100 million through our DRIP, resulting in the issuance of an additional 4,481,504 of our common units. See Note 8 for additional information regarding our ATM program and DRIP.

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 related party costs and expenses attributable to the ASA with EPCO for the periods indicated:

	For the Three Months Ended March 31, 2016	For the Three Months Ended March 31, 2015
Operating costs and expenses	$ 205.4	$ 191.0
General and administrative expenses	27.3	26.6
Total costs and expenses	$ 232.7	$ 217.6

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 March 31, 2016 and December 31, 2015, our accruals for litigation contingencies were $2.6 million and $4.6 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.

<u>ETP Matter</u>
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%, compounded annually.

We do not believe that the verdict or the judgment entered against us is supported by the evidence or the law. We filed our Brief of the Appellant in the Court of Appeals for the Fifth District of Dallas, Texas on March 30, 2015 and ETP filed its Brief of Appellees on June 29, 2015. We filed our Reply Brief of Appellant on September 18, 2015. Oral argument was conducted on April 20, 2016, and the case has now been submitted to the Court of Appeals for its consideration. We intend to vigorously oppose the judgment through the appeals process. As of March 31, 2016, we have not recorded a provision for this matter as management believes payment of damages in this case is not probable.

<u>FTC Inquiry regarding Oiltanking Acquisition</u>
On February 23, 2015, we received a Civil Investigative Demand and a related Subpoena *Duces Tecum* from the FTC requesting specified information relating to the Oiltanking acquisition and our operations. On April 13, 2015, we received a Civil Investigative Demand issued by the Attorney General of the State of Texas requesting copies of the same information and any correspondence with the FTC. We are in the process of complying with the requests and are cooperating with the investigations. Based on the limited information that we have at this time, we are unable to predict the outcome of the investigations.

Contractual Obligations

<u>Scheduled Maturities of Debt</u>
We have long-term and short-term payment obligations under debt agreements. See Note 7 for additional information regarding our scheduled future maturities of debt principal.

Operating Lease Obligations
Consolidated lease and rental expense was $28.5 million and $22.4 million during the three months ended March 31, 2016 and 2015, respectively. Our operating lease commitments at March 31, 2016 did not differ materially from those reported in our 2015 Form 10-K.

Purchase Obligations
Our consolidated purchase obligations at March 31, 2016 did not differ materially from those reported in our 2015 Form 10-K.

Liquidity Option Agreement
We entered into a put option agreement (the "Liquidity Option Agreement") with OTA and Marquard & Bahls ("M&B") in connection with the Oiltanking acquisition. Under the Liquidity Option Agreement, we granted M&B the option to sell to us 100% of the issued and outstanding capital stock of OTA at any time within a 90-day period commencing on February 1, 2020. At that time, OTA's only significant asset is expected to be the Enterprise common units it received in Step 1 of the Oiltanking acquisition, to the extent that such common units are not sold by M&B prior to the option exercise date pursuant to a related registration rights agreement.

If the Liquidity Option is exercised, we would indirectly acquire any Enterprise common units owned by OTA and assume all future income tax obligations of OTA associated with (i) owning common units encumbered by the entity-level taxes of a U.S. corporation and (ii) OTA's tax liabilities resulting from differences in the book and tax basis of such common units at the time of exercise.

The carrying value of the Liquidity Option Agreement, which is a component of "Other long-term liabilities" on our Unaudited Condensed Consolidated Balance Sheet, was $242.9 million and $245.1 million at March 31, 2016 and December 31, 2015, respectively. Results for the three months ended March 31, 2016 reflect a $2.2 million benefit, which is a component of "Other, net" on our Unaudited Condensed Consolidated Statements of Operations, attributable to the Liquidity Option Agreement.

Note 15. Supplemental Cash Flow Information

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

	For the Three Months Ended March 31, 2016	For the Three Months Ended March 31, 2015
Decrease (increase) in:		
Accounts receivable – trade	$ 124.6	$ 837.5
Accounts receivable – related parties	0.4	(0.6)
Inventories	(194.3)	161.0
Prepaid and other current assets	5.3	(3.2)
Other assets	1.3	0.5
Increase (decrease) in:		
Accounts payable – trade	(64.8)	(61.6)
Accounts payable – related parties	(46.7)	(69.6)
Accrued product payables	228.7	(768.7)
Accrued interest	(158.2)	(155.6)
Other current liabilities	(84.4)	(71.9)
Other liabilities	1.7	(6.8)
Net effect of changes in operating accounts	$ (186.4)	$ (139.0)

We incurred liabilities for construction in progress that had not been paid at March 31, 2016 and December 31, 2015 of $422.8 million and $472.8 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 for the periods indicated:

	For the Three Months Ended March 31,	
	2016	2015
Other cash proceeds	$ 13.4	$ 0.5
Total	$ 13.4	$ 0.5

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

	For the Three Months Ended March 31,	
	2016	2015
Net gains (losses) attributable to other asset sales	$ (4.9)	$ 0.1
Total	$ (4.9)	$ 0.1

Note 16. 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. As the parent company of EPO, Enterprise Products Partners L.P. guarantees substantially all of the debt obligations of EPO. 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. See Note 7 for additional information regarding our consolidated debt obligations.

EPO's consolidated subsidiaries have no significant restrictions on their ability to pay distributions or make loans to Enterprise Products Partners L.P.

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
March 31, 2016

	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	$ 215.6	$ 90.1	$ (8.2)	$ 297.5	$ --	$ --	$ 297.5
Accounts receivable – trade, net	750.1	1,700.2	(0.9)	2,449.4	--	--	2,449.4
Accounts receivable – related parties	92.1	680.4	(749.0)	23.5	--	(22.4)	1.1
Inventories	954.3	278.1	(0.3)	1,232.1	--	--	1,232.1
Derivative assets	147.8	87.1	--	234.9	--	--	234.9
Prepaid and other current assets	157.1	227.7	(7.9)	376.9	0.7	--	377.6
Total current assets	2,317.0	3,063.6	(766.3)	4,614.3	0.7	(22.4)	4,592.6
Property, plant and equipment, net	4,141.2	28,530.7	1.4	32,673.3	--	--	32,673.3
Investments in unconsolidated affiliates	39,020.7	4,146.0	(40,482.6)	2,684.1	21,393.6	(21,393.6)	2,684.1
Intangible assets, net	715.8	3,289.7	(14.6)	3,990.9	--	--	3,990.9
Goodwill	459.5	5,285.7	--	5,745.2	--	--	5,745.2
Other assets	149.2	38.7	(136.9)	51.0	0.3	--	51.3
Total assets	$ 46,803.4	$ 44,354.4	$ (41,399.0)	$ 49,758.8	$ 21,394.6	$ (21,416.0)	$ 49,737.4
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 835.8	$ 0.1	$ --	$ 835.9	$ --	$ --	$ 835.9
Accounts payable – trade	324.3	427.0	(8.2)	743.1	0.4	--	743.5
Accounts payable – related parties	713.8	87.7	(764.1)	37.4	22.4	(22.4)	37.4
Accrued product payables	1,257.4	1,434.5	(1.8)	2,690.1	--	--	2,690.1
Accrued liability related to EFS Midstream acquisition	--	996.5	--	996.5	--	--	996.5
Accrued interest	193.5	0.4	--	193.9	--	--	193.9
Other current liabilities	179.5	344.5	(7.9)	516.1	--	--	516.1
Total current liabilities	3,504.3	3,290.7	(782.0)	6,013.0	22.8	(22.4)	6,013.4
Long-term debt	21,904.6	15.2	--	21,919.8	--	--	21,919.8
Deferred tax liabilities	3.4	44.8	(0.8)	47.4	--	2.8	50.2
Other long-term liabilities	9.5	291.9	(136.6)	164.8	242.9	--	407.7
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	21,381.6	40,641.1	(40,655.9)	21,366.8	21,128.9	(21,366.8)	21,128.9
Noncontrolling interests	--	70.7	176.3	247.0	--	(29.6)	217.4
Total equity	21,381.6	40,711.8	(40,479.6)	21,613.8	21,128.9	(21,396.4)	21,346.3
Total liabilities and equity	$ 46,803.4	$ 44,354.4	$ (41,399.0)	$ 49,758.8	$ 21,394.6	$ (21,416.0)	$ 49,737.4

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
December 31, 2015

	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	$ 14.4	$ 71.1	$ (50.6)	$ 34.9	$ --	$ --	$ 34.9
Accounts receivable – trade, net	811.3	1,755.8	2.8	2,569.9	--	--	2,569.9
Accounts receivable – related parties	59.0	795.4	(853.0)	1.4	--	(0.2)	1.2
Inventories	786.9	251.4	(0.2)	1,038.1	--	--	1,038.1
Derivative assets	150.4	108.2	--	258.6	--	--	258.6
Prepaid and other current assets	153.6	249.1	(7.1)	395.6	--	--	395.6
Total current assets	1,975.6	3,231.0	(908.1)	4,298.5	--	(0.2)	4,298.3
Property, plant and equipment, net	3,859.8	28,173.5	1.4	32,034.7	--	--	32,034.7
Investments in unconsolidated affiliates	38,655.0	4,067.3	(40,093.8)	2,628.5	20,540.2	(20,540.2)	2,628.5
Intangible assets, net	721.2	3,330.7	(14.7)	4,037.2	--	--	4,037.2
Goodwill	459.5	5,285.7	--	5,745.2	--	--	5,745.2
Other assets	145.1	47.9	(135.2)	57.8	0.5	--	58.3
Total assets	$ 45,816.2	$ 44,136.1	$ (41,150.4)	$ 48,801.9	$ 20,540.7	$ (20,540.4)	$ 48,802.2
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 1,863.8	$ 0.1	$ --	$ 1,863.9	$ --	$ --	$ 1,863.9
Accounts payable – trade	375.3	535.1	(50.6)	859.8	0.3	--	860.1
Accounts payable – related parties	885.3	62.3	(863.5)	84.1	0.2	(0.2)	84.1
Accrued product payables	997.7	1,489.3	(2.6)	2,484.4	--	--	2,484.4
Accrued liability related to EFS Midstream acquisition	--	993.2	--	993.2	--	--	993.2
Accrued interest	352.0	0.1	--	352.1	--	--	352.1
Other current liabilities	178.7	357.1	(7.0)	528.8	--	--	528.8
Total current liabilities	4,652.8	3,437.2	(923.7)	7,166.3	0.5	(0.2)	7,166.6
Long-term debt	20,661.6	15.3	--	20,676.9	--	--	20,676.9
Deferred tax liabilities	3.4	40.8	(0.8)	43.4	--	2.7	46.1
Other long-term liabilities	14.5	286.9	(135.0)	166.4	245.1	--	411.5
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	20,483.9	40,297.2	(40,266.8)	20,514.3	20,295.1	(20,514.3)	20,295.1
Noncontrolling interests	--	58.7	175.9	234.6	--	(28.6)	206.0
Total equity	20,483.9	40,355.9	(40,090.9)	20,748.9	20,295.1	(20,542.9)	20,501.1
Total liabilities and equity	$ 45,816.2	$ 44,136.1	$ (41,150.4)	$ 48,801.9	$ 20,540.7	$ (20,540.4)	$ 48,802.2

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Three Months Ended March 31, 2016

	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	$ 5,361.9	$ 3,282.7	$ (3,639.3)	$ 5,005.3	$ --	$ --	$ 5,005.3
Costs and expenses:							
Operating costs and expenses	5,091.2	2,695.1	(3,639.4)	4,146.9	--	--	4,146.9
General and administrative costs	6.0	36.8	--	42.8	1.1	--	43.9
Total costs and expenses	5,097.2	2,731.9	(3,639.4)	4,189.7	1.1	--	4,190.8
Equity in income of unconsolidated affiliates	632.7	133.6	(665.2)	101.1	660.1	(660.1)	101.1
Operating income	897.4	684.4	(665.1)	916.7	659.0	(660.1)	915.6
Other income (expense):							
Interest expense	(237.1)	(5.2)	1.7	(240.6)	--	--	(240.6)
Other, net	1.8	1.3	(1.7)	1.4	2.2	--	3.6
Total other income (expense), net	(235.3)	(3.9)	--	(239.2)	2.2	--	(237.0)
Income before income taxes	662.1	680.5	(665.1)	677.5	661.2	(660.1)	678.6
Provision for income taxes	(2.9)	(5.1)	--	(8.0)	--	(0.4)	(8.4)
Net income	659.2	675.4	(665.1)	669.5	661.2	(660.5)	670.2
Net income attributable to noncontrolling interests	--	(1.3)	(8.9)	(10.2)	--	1.2	(9.0)
Net income attributable to entity	$ 659.2	$ 674.1	$ (674.0)	$ 659.3	$ 661.2	$ (659.3)	$ 661.2

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Three Months Ended March 31, 2015

	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	$ 5,579.8	$ 4,825.2	$ (2,932.5)	$ 7,472.5	$ --	$ --	$ 7,472.5
Costs and expenses:							
Operating costs and expenses	5,324.1	4,224.9	(2,932.6)	6,616.4	--	--	6,616.4
General and administrative costs	8.4	40.7	--	49.1	0.2	--	49.3
Total costs and expenses	5,332.5	4,265.6	(2,932.6)	6,665.5	0.2	--	6,665.7
Equity in income of unconsolidated affiliates	627.7	91.6	(630.1)	89.2	636.3	(636.3)	89.2
Operating income	875.0	651.2	(630.0)	896.2	636.1	(636.3)	896.0
Other income (expense):							
Interest expense	(238.3)	(2.8)	2.0	(239.1)	--	--	(239.1)
Other, net	2.0	0.5	(2.0)	0.5	--	--	0.5
Total other expense, net	(236.3)	(2.3)	--	(238.6)	--	--	(238.6)
Income before income taxes	638.7	648.9	(630.0)	657.6	636.1	(636.3)	657.4
Provision for income taxes	(3.2)	(3.1)	--	(6.3)	--	(0.5)	(6.8)
Net income	635.5	645.8	(630.0)	651.3	636.1	(636.8)	650.6
Net loss (income) attributable to noncontrolling interests	--	0.3	(16.0)	(15.7)	--	1.2	(14.5)
Net income attributable to entity	$ 635.5	$ 646.1	$ (646.0)	$ 635.6	$ 636.1	$ (635.6)	$ 636.1

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Three Months Ended March 31, 2016

	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	$ 655.2	$ 630.1	$ (665.0)	$ 620.3	$ 611.9	$ (611.3)	$ 620.9
Comprehensive income attributable to noncontrolling interests	--	(1.3)	(8.9)	(10.2)	--	1.2	(9.0)
Comprehensive income attributable to entity	$ 655.2	$ 628.8	$ (673.9)	$ 610.1	$ 611.9	$ (610.1)	$ 611.9

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Three Months Ended March 31, 2015

	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	$ 621.9	$ 637.8	$ (630.0)	$ 629.7	$ 614.5	$ (615.2)	$ 629.0
Comprehensive income attributable to noncontrolling interests	--	0.3	(16.0)	(15.7)	--	1.2	(14.5)
Comprehensive income attributable to entity	$ 621.9	$ 638.1	$ (646.0)	$ 614.0	$ 614.5	$ (614.0)	$ 614.5

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
For the Three Months Ended March 31, 2016

	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	$ 659.2	$ 675.4	$ (665.1)	$ 669.5	$ 661.2	$ (660.5)	$ 670.2
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	42.5	339.7	(0.1)	382.1	--	--	382.1
Equity in income of unconsolidated affiliates	(632.7)	(133.6)	665.2	(101.1)	(660.1)	660.1	(101.1)
Distributions received on earnings from unconsolidated affiliates	247.2	74.2	(214.7)	106.7	788.5	(788.5)	106.7
Net effect of changes in operating accounts and other operating activities	35.5	(255.3)	42.4	(177.4)	18.8	0.4	(158.2)
Net cash flows provided by operating activities	351.7	700.4	(172.3)	879.8	808.4	(788.5)	899.7
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(307.6)	(687.4)	--	(995.0)	--	--	(995.0)
Proceeds from asset sales	0.1	13.3	--	13.4	--	--	13.4
Other investing activities	(387.5)	(55.7)	260.9	(182.3)	(1,008.6)	1,008.6	(182.3)
Cash used in investing activities	(695.0)	(729.8)	260.9	(1,163.9)	(1,008.6)	1,008.6	(1,163.9)
Financing activities:							
Borrowings under debt agreements	20,000.6	--	--	20,000.6	--	--	20,000.6
Repayments of debt	(19,797.3)	(0.1)	--	(19,797.4)	--	--	(19,797.4)
Cash distributions paid to partners	(788.5)	(222.9)	222.9	(788.5)	(788.3)	788.5	(788.3)
Cash payments made in connection with DERs	--	--	--	--	(2.0)	--	(2.0)
Cash distributions paid to noncontrolling interests	--	(0.5)	(8.2)	(8.7)	--	--	(8.7)
Cash contributions from noncontrolling interests	--	11.1	--	11.1	--	--	11.1
Net cash proceeds from issuance of common units	--	--	--	--	1,011.5	--	1,011.5
Cash contributions from owners	1,008.6	260.9	(260.9)	1,008.6	--	(1,008.6)	--
Other financing activities	--	--	--	--	(21.0)	--	(21.0)
Cash provided by financing activities	423.4	48.5	(46.2)	425.7	200.2	(220.1)	405.8
Net change in cash and cash equivalents	80.1	19.1	42.4	141.6	--	--	141.6
Cash and cash equivalents, January 1	--	69.6	(50.6)	19.0	--	--	19.0
Cash and cash equivalents, March 31	$ 80.1	$ 88.7	$ (8.2)	$ 160.6	$ --	$ --	$ 160.6

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
For the Three Months Ended March 31, 2015

	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	$ 635.5	$ 645.8	$ (630.0)	$ 651.3	$ 636.1	$ (636.8)	$ 650.6
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	32.9	334.6	(0.1)	367.4	--	--	367.4
Equity in income of unconsolidated affiliates	(627.7)	(91.6)	630.1	(89.2)	(636.3)	636.3	(89.2)
Distributions received on earnings from unconsolidated affiliates	633.9	97.5	(597.0)	134.4	726.7	(726.7)	134.4
Net effect of changes in operating accounts and other operating activities	(146.6)	13.0	6.9	(126.7)	17.0	0.5	(109.2)
Net cash flows provided by operating activities	528.0	999.3	(590.1)	937.2	743.5	(726.7)	954.0
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(234.2)	(559.0)	--	(793.2)	--	--	(793.2)
Proceeds from asset sales	--	0.5	--	0.5	--	--	0.5
Other investing activities	(252.0)	(24.0)	179.6	(96.4)	(468.4)	468.4	(96.4)
Cash used in investing activities	(486.2)	(582.5)	179.6	(889.1)	(468.4)	468.4	(889.1)
Financing activities:							
Borrowings under debt agreements	9,182.5	--	--	9,182.5	--	--	9,182.5
Repayments of debt	(8,953.2)	--	--	(8,953.2)	--	--	(8,953.2)
Cash distributions paid to partners	(726.7)	(613.1)	613.1	(726.7)	(703.8)	726.7	(703.8)
Cash payments made in connection with DERs	--	--	--	--	(1.2)	--	(1.2)
Cash distributions paid to noncontrolling interests	--	(0.4)	(16.1)	(16.5)	--	--	(16.5)
Cash contributions from noncontrolling interests	--	4.4	(0.4)	4.0	--	--	4.0
Net cash proceeds from issuance of common units	--	--	--	--	468.4	--	468.4
Cash contributions from owners	468.4	179.2	(179.2)	468.4	--	(468.4)	--
Other financing activities	0.1	--	--	0.1	(38.5)	--	(38.4)
Cash used in financing activities	(28.9)	(429.9)	417.4	(41.4)	(275.1)	258.3	(58.2)
Net change in cash and cash equivalents	12.9	(13.1)	6.9	6.7	--	--	6.7
Cash and cash equivalents, January 1	18.7	70.4	(14.7)	74.4	--	--	74.4
Cash and cash equivalents, March 31	$ 31.6	$ 57.3	$ (7.8)	$ 81.1	$ --	$ --	$ 81.1

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

For the Three Months Ended March 31, 2016 and 2015

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, 2015, as filed on February 26, 2016 (the "2015 Form 10-K"). Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States ("U.S.").

Key References Used in this Management's Discussion and Analysis

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 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 Directors (the "Board") of Enterprise GP; (ii) Richard H. Bachmann, who is also a director and Vice Chairman of the Board of Enterprise GP; and (iii) Dr. Ralph S. Cunningham. Ms. Duncan Williams and Mr. Bachmann also currently serve as managers of Dan Duncan LLC along with W. Randall Fowler, who is also a director and President of Enterprise GP.

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 by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Duncan Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President and Chief Executive Officer of EPCO. Ms. Duncan Williams and Mr. Bachmann also currently serve as directors of EPCO along with Mr. Fowler, who is also the Executive Vice President and Chief Administrative Officer of EPCO. EPCO, together with its privately held affiliates, owned approximately 33.3% of our limited partner interests at March 31, 2016.

References to "Oiltanking" and "Oiltanking GP" mean Oiltanking Partners, L.P. and OTLP GP, LLC, the general partner of Oiltanking, respectively. In October 2014, we acquired approximately 65.9% of the limited partner interests of Oiltanking, all of the member interests of Oiltanking GP and the incentive distribution rights ("IDRs") held by Oiltanking GP from Oiltanking Holding Americas, Inc. as the first step of a two-step acquisition of Oiltanking. In February 2015, we completed the second step of this transaction consisting of the acquisition of the noncontrolling interests in Oiltanking.

References to "Offshore Business" refer to the Gulf of Mexico operations we sold to Genesis Energy, L.P. ("Genesis") in July 2015.

References to "EFS Midstream" mean EFS Midstream LLC, which we acquired in July 2015 from affiliates of Pioneer Natural Resources Company and Reliance Industries Limited.

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

As used in this quarterly report, the phrase "quarter-to-quarter" means the first quarter of 2016 compared to the first quarter of 2015.

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 2015 Form 10-K and within Part II, Item 1A of this quarterly report. 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 liquid ("NGL") 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 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; 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. Our assets currently include approximately 49,000 miles of pipelines; 250 MMBbls of storage capacity for NGLs, crude oil, petrochemicals and refined products; and 14 Bcf of natural gas storage capacity.

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.

Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & Services. On July 24, 2015, we completed the sale of our Offshore Business, which primarily consisted of our Offshore Pipelines & Services segment. Our consolidated financial statements reflect ownership of the Offshore Business through July 24, 2015. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements for additional information regarding our business segments.

As a result of our acquisition of the member interests of EFS Midstream effective July 1, 2015, we began consolidating the financial statements of EFS Midstream as of that date.

We provide investors access to additional information regarding our partnership, including information relating to our governance procedures and principles, through our website, *www.enterpriseproducts.com*.

Significant Recent Developments

Start-Up of South Eddy Natural Gas Processing Plant in May 2016

In May 2016, we announced that our new cryogenic natural gas processing plant located in Eddy County, New Mexico (the "South Eddy" plant) had been placed into service. We constructed the South Eddy plant to serve producers in the Delaware Basin region. The South Eddy plant has a nameplate natural gas processing capacity of 200 MMcf/d and is capable of extracting up to 25 MBPD of NGLs. We also completed construction of approximately 90 miles of natural gas gathering pipelines to supply the new plant.

In addition to the South Eddy plant and its related natural gas gathering infrastructure, we also completed a 71-mile extension of our Mid-America Pipeline System. This extension provides producers in the Delaware Basin with NGL takeaway capacity and direct access to our integrated network of NGL assets.

Issuance of Common Units under our ATM Program and DRIP

For the period January 1, 2016 through April 8, 2016, we sold 60,947,078 common units under our "at-the-market" ("ATM") program for aggregate gross proceeds of $1.45 billion. This includes 3,830,256 common units sold in January 2016 to privately held affiliates of EPCO, which generated gross proceeds of $100 million. After taking into account applicable costs, our transactions under the ATM program during this period resulted in aggregate net cash proceeds of $1.44 billion.

In addition, we issued a total of 7,162,744 common units under our distribution reinvestment plan ("DRIP") during the three months ended March 31, 2016, which generated net cash proceeds of $159.8 million. This includes $100 million reinvested under the DRIP by privately held affiliates of EPCO in February 2016.

We used the proceeds from these sales for the repayment of debt and general company purposes.

Issuance of $1.25 Billion of Senior Notes

In April 2016, EPO issued $575 million in principal amount of 2.85% senior notes due April 2021 ("Senior Notes RR"), $575 million in principal amount of 3.95% senior notes due February 2027 ("Senior Notes SS") and $100 million in principal amount of 4.90% reopened senior notes due May 2046 ("Senior Notes QQ"). Senior Notes RR, SS and QQ were issued at 99.898%, 99.760% and 95.516% of their principal amounts, respectively. Net proceeds from the issuance of these senior notes were used as follows: (i) the repayment of amounts then outstanding under EPO's commercial paper program, which included amounts we used to repay $750 million in principal amount of Senior Notes AA that matured in February 2016, and (ii) for general company purposes.

Enterprise Management to Recommend 5.2% Distribution Growth for 2016

In January 2016, our management announced plans to recommend to the Board of Enterprise GP cash distributions totaling $1.61 per unit with respect to 2016, which, if approved by the Board, would represent a 5.2% increase compared to a total of $1.53 per unit of cash distributions declared with respect to calendar year 2015. In April 2016, our management recommended, and the Board of Enterprise GP declared, cash distributions of $0.395 per unit with respect to the first quarter of 2016. Historically, it has been our practice to not provide guidance with respect to distribution growth; however, due to actions by some of our midstream peers to reduce or freeze their dividends/distributions, we believed it was important to provide our investors with visibility into management's expected recommendations for our distribution growth in 2016 based on our view of future business conditions at the time of announcement.

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 March 31, 2016	For the Three Months Ended March 31, 2015
Revenues	$ 5,005.3	$ 7,472.5
Costs and expenses:		
Operating costs and expenses:		
Cost of sales	3,208.3	5,678.1
Other operating costs and expenses	573.8	559.8
Depreciation, amortization and accretion expenses	358.2	345.3
Net losses (gains) attributable to asset sales	4.9	(0.1)
Non-cash asset impairment charges	1.7	33.3
Total operating costs and expenses	4,146.9	6,616.4
General and administrative costs	43.9	49.3
Total costs and expenses	4,190.8	6,665.7
Equity in income of unconsolidated affiliates	101.1	89.2
Operating income	915.6	896.0
Interest expense	(240.6)	(239.1)
Other, net	3.6	0.5
Provision for income taxes	(8.4)	(6.8)
Net income	670.2	650.6
Net income attributable to noncontrolling interests	(9.0)	(14.5)
Net income attributable to limited partners	$ 661.2	$ 636.1

Consolidated Revenues

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 March 31, 2016	For the Three Months Ended March 31, 2015
NGL Pipelines & Services:		
Sales of NGLs and related products	$ 1,943.5	$ 2,242.2
Midstream services	460.3	434.1
Total	2,403.8	2,676.3
Crude Oil Pipelines & Services:		
Sales of crude oil	1,121.1	2,570.7
Midstream services	167.5	107.3
Total	1,288.6	2,678.0
Natural Gas Pipelines & Services:		
Sales of natural gas	315.0	476.3
Midstream services	235.0	257.6
Total	550.0	733.9
Petrochemical & Refined Products Services:		
Sales of petrochemicals and refined products	553.2	1,151.0
Midstream services	209.7	198.1
Total	762.9	1,349.1
Offshore Pipelines & Services:		
Sales of natural gas	--	--
Sales of crude oil	--	1.1
Midstream services	--	34.1
Total	--	35.2
Total consolidated revenues	$ 5,005.3	$ 7,472.5

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)
2015 by quarter:										
1st Quarter	$2.99	$0.19	$0.53	$0.68	$0.68	$1.10	$0.50	$0.37	$48.63	$52.83
2nd Quarter	$2.65	$0.18	$0.46	$0.59	$0.60	$1.26	$0.42	$0.29	$57.94	$62.97
3rd Quarter	$2.77	$0.19	$0.40	$0.55	$0.55	$0.98	$0.33	$0.21	$46.43	$50.17
4th Quarter	$2.27	$0.18	$0.42	$0.60	$0.61	$0.97	$0.31	$0.18	$42.18	$43.54
2015 Averages	$2.67	$0.18	$0.45	$0.61	$0.61	$1.08	$0.39	$0.26	$48.80	$52.38
2016 by quarter:										
1st Quarter	$2.09	$0.16	$0.38	$0.53	$0.53	$0.76	$0.31	$0.18	$33.45	$35.11

(1) Natural gas prices are based on Henry-Hub Inside FERC commercial index prices as reported by Platts, which is a division of McGraw Hill Financial, Inc.

(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 WTI as measured on the New York Mercantile Exchange ("NYMEX") and for LLS as reported by Platts.

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. Crude oil, natural gas and NGL prices have been depressed since the fourth quarter of 2014 primarily due to an oversupply of these commodities on world markets. The weighted-average indicative market price for NGLs was $0.40 per gallon in the first quarter of 2016 versus $0.54 per gallon during the first quarter of 2015.

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 12 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

Total revenues for the first quarter of 2016 decreased $2.47 billion when compared to total revenues for the first quarter of 2015. Revenues from the marketing of crude oil, natural gas and refined products decreased $1.95 billion quarter-to-quarter primarily due to lower sales prices and volumes, which accounted for a $1.68 billion decrease and a $275.0 million decrease, respectively. Revenues from the marketing of NGLs and petrochemicals decreased a net $517.3 million quarter-to-quarter primarily due to lower sales prices, which accounted for a $958.6 million decrease, partially offset by a $441.3 million increase due to higher sales volumes. Revenues from midstream services increased a net $41.3 million quarter-to-quarter primarily due to contributions from recently acquired assets, which were partially offset by a decrease due to the sale of our Offshore Business. Revenues for the first quarter of 2016 include $65.0 million from the assets we acquired effective July 1, 2015 in connection with the EFS Midstream acquisition. Revenues from midstream services decreased $34.4 million quarter-to-quarter due to the sale of our Offshore Business effective July 24, 2015.

Operating costs and expenses

Total operating costs and expenses for the first quarter of 2016 decreased $2.47 billion when compared to total operating costs and expenses for the first quarter of 2015. The cost of sales associated with our marketing of crude oil, natural gas and refined products decreased $1.8 billion quarter-to-quarter primarily due to lower purchase prices, which accounted for a $1.53 billion decrease, and lower sales volumes, which accounted for an additional $268.3 million decrease. The cost of sales associated with our marketing of NGLs and petrochemicals decreased a net $662.1 million quarter-to-quarter primarily due to lower purchase prices, which accounted for a $978.4 million decrease, partially offset by a $316.3 million increase due to higher sales volumes.

Other operating costs and expenses increased a net $14.0 million quarter-to-quarter. The inclusion of assets attributable to the EFS Midstream acquisition accounted for an $11.9 million increase. Other operating costs and expenses also decreased $8.9 million quarter-to-quarter due to the sale of our Offshore Business.

Depreciation, amortization and accretion expense in operating costs and expenses for the first quarter of 2016 increased a net $12.9 million when compared to the first quarter of 2015 primarily due to a $35.9 million increase attributable to assets we constructed and placed into service or acquired since the first quarter of 2015, partially offset by a $23.0 million quarter-to-quarter decrease attributable to the sale of our Offshore Business.

Operating costs and expenses also include $1.7 million and $33.3 million of non-cash asset impairment charges for the first quarters of 2016 and 2015, respectively. Our non-cash asset impairment charges for the first quarter of 2015 primarily relate to crude oil and natural gas pipeline assets in Texas.

General and administrative costs

General and administrative costs for the first quarter of 2016 decreased $5.4 million when compared to the first quarter of 2015 primarily due to lower costs for professional services.

Equity in income of unconsolidated affiliates

Equity income from our unconsolidated affiliates for the first quarter of 2016 increased a net $11.9 million when compared to the same period in 2015 primarily due to a $32.7 million increase in earnings from our investments in crude oil and NGL pipelines, partially offset by a $20.2 million reduction in equity earnings attributable to the sale of our Offshore Business.

Interest expense
Interest expense for the first quarter of 2016 increased $1.5 million when compared to the same period in 2015. The following table presents the components of our consolidated interest expense for the periods indicated (dollars in millions):

	For the Three Months Ended March 31, 2016	For the Three Months Ended March 31, 2015
Interest charged on debt principal outstanding	$ 268.3	$ 257.1
Impact of interest rate hedging program, including related amortization	6.4	4.7
Interest costs capitalized in connection with construction projects (1)	(42.5)	(29.6)
Other (2)	8.4	6.9
Total	$ 240.6	$ 239.1

(1) We capitalize interest costs incurred on funds used to construct property, plant and equipment while the asset is in its construction phase. 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. When capitalized interest is recorded, it reduces interest expense from what it would be otherwise. Capitalized interest amounts fluctuate 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 $11.2 million quarter-to-quarter primarily due to increased debt principal amounts outstanding during the first quarter of 2016, which accounted for a $14.2 million increase, partially offset by the effect of lower overall interest rates in the first quarter of 2016, which accounted for a $3.0 million decrease. Our weighted-average debt principal balance for the first quarter of 2016 was $22.96 billion compared to $21.67 billion for the first quarter of 2015. 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.

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 March 31, 2016	For the Three Months Ended March 31, 2015
NGL Pipelines & Services	$ 783.7	$ 695.2
Crude Oil Pipelines & Services	202.3	214.0
Natural Gas Pipelines & Services	177.7	204.5
Petrochemical & Refined Products Services	154.8	174.6
Offshore Pipelines & Services	--	46.1
Total	$ 1,318.5	$ 1,334.4

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 quarter-to-quarter 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 March 31, 2016	2015
Segment gross operating margin:		
Natural gas processing and related NGL marketing activities	$ 233.9	$ 240.2
NGL pipelines, storage and terminals	426.7	328.2
NGL fractionation	123.1	126.8
Total	$ 783.7	$ 695.2
Selected volumetric data:		
NGL pipeline transportation volumes (MBPD)	2,954	2,426
NGL marine terminal volumes (MBPD)	456	263
NGL fractionation volumes (MBPD)	836	798
Equity NGL production (MBPD) (1)	145	134
Fee-based natural gas processing (MMcf/d) (2)	4,781	4,784

(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 natural gas processing and related NGL marketing activities for the first quarter of 2016 decreased $6.3 million when compared to the first quarter of 2015. Gross operating margin from our natural gas processing plants decreased $43.5 million quarter-to-quarter primarily due to lower processing margins. Gross operating margin from our NGL marketing activities for the first quarter of 2016 increased a net $37.2 million when compared to the first quarter of 2015 primarily due to higher sales volumes, which accounted for a $75.0 million increase, partially offset by a $37.8 million decrease due to lower sales margins. NGL marketing sales volumes were higher during the first quarter of 2016 when compared to the first quarter of 2015 primarily due to expansion projects we completed during 2015 at our Houston Ship Channel marine terminal.

NGL pipelines, storage and terminals. Gross operating margin from NGL pipelines, storage and terminal assets for the first quarter of 2016 increased $98.5 million when compared to the first quarter of 2015. Gross operating margin from our Houston Ship Channel marine terminal and related pipeline increased $34.2 million quarter-to-quarter primarily due to higher marine terminal and pipeline transportation volumes of 196 MBPD and 164 MBPD, respectively. In April 2015, we completed an expansion project at our Houston Ship Channel marine terminal that increased our ability to load cargos of LPGs from 7.5 MMBbls per month to approximately 9.0 MMBbls per month. In December 2015, we completed a second expansion project at the terminal further increasing our ability to load cargos of LPGs to approximately 16.0 MMBbls per month.

Gross operating margin from our ATEX and Aegis Ethane Pipelines increased a combined $28.6 million quarter-to-quarter primarily due to a combined 148 MBPD increase in transportation volumes. The second segment of our Aegis Ethane Pipeline was placed into service in September 2015. The third and final segment of our Aegis Ethane Pipeline was placed into service in December 2015.

Gross operating margin from the Mid-America Pipeline System, Seminole Pipeline and related terminals increased $13.2 million quarter-to-quarter primarily due to higher transportation volumes of 86 MBPD. NGL volumes transported on these pipelines for delivery to Mont Belvieu, Texas were higher during the first quarter of 2016 when compared to the first quarter of 2015 primarily due to commodity price differences between Conway, Kansas and Mont Belvieu. Gross operating margin from our South Texas NGL Pipeline System increased $6.3 million quarter-to-quarter attributable to a 36 MBPD increase in transportation volumes. The South Texas NGL Pipeline System benefited from a quarter-to-quarter increase in production from the Eagle Ford Shale region and an increase in mixed NGLs received from our Seminole Pipeline for delivery to our storage and fractionation complex in Mont Belvieu, Texas.

Gross operating margin from our Tri-States NGL Pipeline increased $4.7 million quarter-to-quarter due to a $2.1 million increase from higher transportation volumes of 7 MBPD (net to our interest), higher tariffs, which accounted for a $2.0 million increase, and a $0.6 million decrease in operating expenses. Lastly, gross operating margin from our investments in the Front Range Pipeline, Texas Express Pipeline and Texas Express Gathering System for the first quarter of 2016 increased $3.7 million primarily due to a combined 17 MBPD increase in transportation volumes (net to our interest) when compared to the first quarter of 2015.

NGL fractionation. Gross operating margin from NGL fractionation for the first quarter of 2016 decreased $3.7 million when compared to the first quarter of 2015. Gross operating margin from our Mont Belvieu NGL fractionators decreased a net $6.1 million quarter-to-quarter primarily due to a combined $10.2 million decrease in product blending and other fee revenues, partially offset by a $4.5 million increase due to higher fractionation volumes of 11 MBPD (net to our interest). Certain of the product blending and other fee revenues are influenced by energy commodity prices, which have generally declined since the beginning of 2014.

Crude Oil Pipelines & Services

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

	For the Three Months Ended March 31,	
	2016	**2015**
Segment gross operating margin	$ 202.3	$ 214.0
Selected volumetric data:		
Crude oil pipeline transportation volumes (MBPD)	1,393	1,384
Crude oil marine terminal volumes (MBPD)	479	644

Gross operating margin from our Crude Oil Pipelines & Services segment for the first quarter of 2016 decreased $11.7 million when compared to the first quarter of 2015. Gross operating margin from our crude oil marketing and related trucking activities decreased $70.5 million quarter-to-quarter primarily due to lower crude oil sales margins, which includes the impact of approximately $13.3 million of non-cash mark-to-market losses in the first quarter of 2016 on financial instruments related to blending activities. As a result of lower crude oil prices, regional price spreads were less than the costs incurred by our marketing business, such as transportation costs on the Seaway Pipeline. Our crude oil marketing business has contracted for 75 MBPD of firm capacity on the Seaway Pipeline of which 25 MBPD of capacity terminates June 1, 2017 and the remaining 50 MBPD terminates February 1, 2018. Sales margins on Seaway Pipeline-related capacity were $31.1 million lower in the first quarter of 2016 compared to the first quarter of 2015.

Gross operating margin from our South Texas Crude Oil Pipeline System decreased $23.8 million quarter-to-quarter primarily due to a 76 MBPD decrease in volumes, which accounted for a $17.9 million decrease, and a $4.0 million decrease due to lower average transportation fees. The decrease in crude oil transportation volumes was primarily due to lower Eagle Ford Shale production attributable to reduced drilling activity.

The EFS Midstream system, which we acquired effective July 1, 2015, contributed $53.3 million of gross operating margin and 63 MBPD of throughput volumes for the first quarter of 2016. Gross operating margin from crude oil terminaling services at our Houston Ship Channel, Beaumont Marine West and Enterprise Crude Houston ("ECHO") facilities increased a combined $19.5 million quarter-to-quarter primarily due to expansion projects (e.g., the construction of new storage tanks) we completed at these facilities since the first quarter of 2015. Our crude oil marine terminal volumes decreased 165 MBPD quarter-to-quarter primarily due to lower crude oil volumes unloaded from marine vessels (i.e., crude oil imports) at our Houston Ship Channel and Beaumont Marine West facilities.

Gross operating margin from our equity investment in the Seaway Pipeline increased $11.0 million quarter-to-quarter. In February 2016, the Federal Energy Regulatory Commission ("FERC") issued its decision regarding the various challenges to Seaway's committed and uncommitted rates in FERC Docket No. IS12-226-000. The FERC upheld the committed rates and rejected the claim that the committed rates should be reduced to cost-based levels. The FERC's rulings regarding the uncommitted rates were also largely favorable to Seaway. Seaway submitted a compliance filing on March 17, 2016 calculating revised uncommitted rates consistent with the FERC's order. The compliance filing was not challenged. As a result of the FERC ruling, Seaway recognized $22.2 million of revenues (on a 100% basis) in the first quarter of 2016 that had previously been deferred.

Natural Gas Pipelines & Services

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

	For the Three Months Ended March 31,	
	2016	**2015**
Segment gross operating margin	$ 177.7	$ 204.5
Selected volumetric data:		
Natural gas pipeline transportation volumes (BBtus/d)	11,895	12,503

Gross operating margin from our Natural Gas Pipelines & Services segment for the first quarter of 2016 decreased $26.8 million when compared to the first quarter of 2015. Gross operating margin from our Texas Intrastate System decreased $9.4 million quarter-to-quarter primarily due to lower firm capacity reservation revenues attributable to decreased producer activity in the Eagle Ford Shale. Gross operating margin from our Acadian Gas and Piceance Basin Systems decreased a combined $7.1 million quarter-to-quarter primarily due to reduced transportation fees. Gross operating margin from our San Juan Gathering System decreased $5.5 million quarter-to-quarter primarily due to lower gathering volumes of 98 BBtus/d, which accounted for a $2.2 million decrease, and a $1.8 million decrease in gathering fee revenues. Gathering fees on the San Juan Gathering System, which are indexed to regional natural gas prices, decreased quarter-to-quarter due to lower natural gas prices in the first quarter of 2016 when compared to the first quarter of 2015.

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 March 31,	
	2016	**2015**
Segment gross operating margin:		
Propylene fractionation and related activities	$ 52.1	$ 64.4
Butane isomerization and related operations	16.1	6.9
Octane enhancement and related plant operations	(10.2)	1.1
Refined products pipelines and related activities	87.0	86.3
Other	9.8	15.9
Total	$ 154.8	$ 174.6
Selected volumetric data:		
Propylene fractionation volumes (MBPD)	69	74
Butane isomerization volumes (MBPD)	110	62
Standalone DIB processing volumes (MBPD)	96	65
Octane additive and related plant production volumes (MBPD)	10	8
Pipeline transportation volumes, primarily refined products & petrochemicals (MBPD)	852	738
Refined products and petrochemical marine terminal volumes (MBPD)	347	324

Propylene fractionation and related activities. Gross operating margin from propylene fractionation and related activities for the first quarter of 2016 decreased $12.3 million when compared to the first quarter of 2015. This decrease is primarily due to lower propylene sales margins in the first quarter of 2016 when compared to the first quarter of 2015.

Butane isomerization and deisobutanizer operations. Gross operating margin from butane isomerization and deisobutanizer ("DIB") operations for the first quarter of 2016 increased $9.2 million when compared to the first quarter of 2015. This increase is primarily due to higher butane isomerization and standalone DIB processing volumes of 48 MBPD and 31 MBPD, respectively.

Octane enhancement and HPIB plant operations. Gross operating margin from our octane enhancement facility and high purity isobutylene ("HPIB") plant for the first quarter of 2016 decreased $11.3 million when compared to the first quarter of 2015. This decrease is primarily due to lower sales volumes, which accounted for a $6.7 million decrease, lower sales margins, which accounted for an additional $1.5 million decrease, and a $2.6 million quarter-to-quarter increase in operating expenses. Our octane enhancement facility was out of service for extended periods during the first quarters of 2016 and 2015 for major maintenance activities.

Refined products pipelines and related activities. Gross operating margin from refined products pipelines and related marketing activities for the first quarter of 2016 increased $0.7 million when compared to the first quarter of 2015. Gross operating margin from refined products terminaling services at our facilities in Beaumont, Texas increased a net $5.2 million quarter-to-quarter due to a $9.1 million increase in revenues, the primary driver of which was an 18 MBPD increase in marine terminal volumes, partially offset by a $3.9 million increase in operating expenses. Gross operating margin from our refined products marketing activities decreased $4.3 million quarter-to-quarter primarily due to lower sales margins, which includes a $1.2 million decrease attributable to non-cash mark-to-market losses.

Gross operating margin for the TE Products Pipeline and related terminals increased $0.9 million quarter-to-quarter. Interstate pipeline transportation volumes on our TE Products Pipeline increased a net 16 MBPD quarter-to-quarter primarily due to a 26 MBPD increase in refined products transportation volumes, which was partially offset by a 10 MBPD decrease in NGL transportation volumes resulting from warmer weather and reduced terminal demand in the Northeast U.S. Intrastate refined products and petrochemical pipeline transportation volumes on our TE Products Pipeline increased a combined 69 MBPD quarter-to-quarter.

Other. Gross operating margin from these activities decreased $6.1 million quarter-to-quarter primarily due to lower demand for marine transportation services attributable to the lower commodity pricing environment.

<u>*Offshore Pipelines & Services*</u>
We sold our Offshore Business to Genesis on July 24, 2015. The following table presents segment gross operating margin and selected volumetric data for the Offshore Pipelines & Services segment for three months ended March 31, 2015 (dollars in millions, volumes as noted):

Segment gross operating margin	$	46.1
Selected volumetric data:		
Natural gas transportation volumes (BBtus/d)		619
Crude oil transportation volumes (MBPD)		340
Platform natural gas processing (MMcf/d)		124
Platform crude oil processing (MBPD)		15

Liquidity and Capital Resources

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 for the reasonably foreseeable future. At March 31, 2016, we had $3.6 billion of consolidated liquidity, which was comprised of $3.43 billion of available borrowing capacity under EPO's revolving credit facilities and $160.6 million of unrestricted cash on hand.

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 (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. The 2013 Shelf will expire in June 2016, at which time we expect to file a replacement universal shelf registration statement.

As discussed under “Significant Recent Developments” within this Item 2, we sold 60,947,078 common units under our ATM program, which generated aggregate gross proceeds of $1.45 billion, from January 1, 2016 through April 8, 2016. Pursuant to this 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. After taking into account the aggregate sales price of common units sold under our ATM program through April 8, 2016, our capacity under the applicable registration statement was reduced to $415.7 million. On April 22, 2016, we filed a registration statement with the SEC that (when declared effective) will replace our existing registration statement with respect to the ATM program and increase the available capacity under the ATM program to allow us to issue up to an aggregate $2.17 billion of additional common units, inclusive of the remaining capacity under such existing registration statement.

Consolidated Debt

The following table presents scheduled maturities of our consolidated debt obligations outstanding at March 31, 2016 for the years indicated (dollars in millions):

		Scheduled Maturities of Debt					
	Total	**Remainder of 2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**
Commercial Paper Notes	$ 2,072.0	$ 2,072.0	$ --	$ --	$ --	$ --	$ --
Senior Notes	19,400.0	--	800.0	1,100.0	1,500.0	1,500.0	14,500.0
Junior Subordinated Notes	1,474.4	--	--	--	--	--	1,474.4
Total	$ 22,946.4	$ 2,072.0	$ 800.0	$ 1,100.0	$ 1,500.0	$ 1,500.0	$ 15,974.4

For additional information regarding our debt agreements, see Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

As discussed under “Significant Recent Developments” within this Item 2, we issued $1.25 billion of senior notes in April 2016. These notes were issued under the 2013 Shelf. 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 an indenture containing certain covenants, which generally restrict EPO’s ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions.

Issuance of Common Units

The following table summarizes the issuance of common units in connection with our underwritten equity offerings, ATM program, distribution reinvestment plan (“DRIP”) and employee unit purchase plan (“EUPP”) for the period January 1, 2016 through April 8, 2016 (dollars in millions, number of units issued as shown):

	Number of Common Units Issued	**Net Cash Proceeds Received**
Common units issued in connection with ATM program:		
January 1, 2016 through March 31, 2016	35,396,147	$ 849.0
April 1, 2016 through April 8, 2016	25,550,931	592.0
Common units issued in connection with DRIP and EUPP	7,282,006	162.5
Total	68,229,084	$ 1,603.5

Privately held affiliates of EPCO invested an aggregate $200 million in us through our ATM program and the DRIP during the three months ended March 31, 2016 (this amount being a component of the net cash proceeds presented in the preceding table).

After taking into account the number of common units issued under the DRIP through March 31, 2016, we have the capacity to issue an additional 7,905,254 common units under this plan. We expect to file a new registration statement during the second quarter of 2016 to increase the number of common units available for issuance under the DRIP.

For additional information regarding our issuance of common units and related registration statements, see Note 8 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Credit Ratings
As of April 30, 2016, 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 Three Months Ended March 31,	
	2016	**2015**
Net cash flows provided by operating activities	$ 899.7	$ 954.0
Cash used in investing activities	1,163.9	889.1
Cash provided by (used in) financing activities	405.8	(58.2)

Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. We operate in the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, crude oil, petrochemicals and refined products. As such, changes in the prices of hydrocarbon products and in the relative price levels among hydrocarbon products could have a material adverse effect on our financial position, results of operations and cash flows. Changes in prices may impact demand for hydrocarbon products, which in turn may impact production, demand and the volumes of products for which we provide services. In addition, decreases in demand may be caused by other factors, including prevailing economic conditions, reduced demand by consumers for the end products made with hydrocarbon products, increased competition, adverse weather conditions and government regulations affecting prices and production levels. We may also incur credit and price risk to the extent counterparties do not fulfill their obligations to us in connection with our marketing of natural gas, NGLs, propylene, refined products and/or crude oil and long-term take-or-pay agreements. 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 2015 Form 10-K and under Part II, Item 1A of this quarterly report.

<u>*Comparison of Three Months Ended March 31, 2016 with Three Months Ended March 31, 2015*</u>
The following information highlights significant quarter-to-quarter fluctuations in our consolidated cash flow amounts:

Operating Activities. Net cash flows provided by operating activities for the three months ended March 31, 2016 decreased $54.3 million when compared to the same period in 2015. The decrease in cash provided by operating activities was primarily due to:

- a $47.4 million quarter-to-quarter decrease in cash primarily due to the timing of cash receipts and payments related to operations; and

- a $27.7 million quarter-to-quarter decrease in cash distributions received from unconsolidated affiliates primarily due to the sale of our Offshore Business in July 2015; partially offset by

- a $20.8 million increase in cash attributable to higher partnership income in the three months ended March 31, 2016 compared to the same period in 2015 (after adjusting our $19.6 million quarter-to-quarter increase in net income for changes in the non-cash items identified on our Unaudited Condensed Statements of Consolidated Cash Flows).

For information regarding significant quarter-to-quarter 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 three months ended March 31, 2016 increased $274.8 million when compared to the same period in 2015 primarily due to:

- a $201.8 million quarter-to-quarter increase in capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs; and

- a $92.8 million quarter-to-quarter increase in restricted cash requirements; partially offset by

- a $12.9 million quarter-to-quarter increase in proceeds from asset sales.

Financing Activities. Net cash provided by financing activities for the three months ended March 31, 2016 was $405.8 million compared to net cash used in financing activities of $58.2 million for the same period in 2015. The $464.0 million quarter-to-quarter change in cash flow from financing activities was primarily due to:

- a $543.1 million quarter-to-quarter increase in net cash proceeds from the issuance of common units. We issued an aggregate 42,678,153 common units in connection with our ATM program, DRIP and EUPP during the three months ended March 31, 2016, which generated $1.01 billion of net cash proceeds. This compares to an aggregate 14,291,593 common units we issued in connection with our ATM program, DRIP and EUPP during the same period in 2015, which collectively generated $468.4 million of net cash proceeds; partially offset by

- an $84.5 million quarter-to-quarter increase in cash distributions paid to limited partners during the three months ended March 31, 2016 when compared to the same period in 2015. 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 $26.1 million quarter-to-quarter decrease in net borrowings under our consolidated debt agreements. Net issuances under EPO's commercial paper program were $953.3 million during the three months ended March 31, 2016 compared $479.3 million during the same period in 2015. In addition, EPO repaid $750.0 million in principal amount of debt obligations during the three months ended March 31, 2016 compared to the repayment of $250.0 million in principal amount of senior notes during the same period in 2015.

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 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 IDRs or other equity interests. See "Significant Recent Developments" within this Item 2 for additional information regarding cash distributions with respect to 2016.

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 March 31, 2016	For the Three Months Ended March 31, 2015
Net income attributable to limited partners (1)	$ 661.2	$ 636.1
Adjustments to GAAP net income attributable to limited partners to derive non-GAAP distributable cash flow:		
Add depreciation, amortization and accretion expenses	382.1	367.4
Add non-cash asset impairment charges	1.7	33.3
Add loss or subtract gains attributable to asset sales, net	4.9	(0.1)
Add cash proceeds from asset sales (2)	13.4	0.5
Add cash distributions received from unconsolidated affiliates (3)	115.8	134.4
Subtract equity in income of unconsolidated affiliates (3)	(101.1)	(89.2)
Subtract sustaining capital expenditures (4)	(59.3)	(50.7)
Add deferred income tax expense or subtract benefit, as applicable	4.1	1.5
Other, net	30.8	(3.5)
Distributable cash flow	$ 1,053.6	$ 1,029.7
Total cash distributions paid to limited partners with respect to period	$ 825.4	$ 735.7
Cash distribution per unit declared by Enterprise GP with respect to period (5)	$ 0.3950	$ 0.3750
Total distributable cash flow retained by partnership with respect to period (6)	$ 228.2	$ 294.0
Distribution coverage ratio (7)	1.3x	1.4x

(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 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) Reflects both distributions received on earnings from unconsolidated affiliates and those attributable to a return of capital from unconsolidated affiliates. For information regarding our unconsolidated affiliates, see Note 5 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. For purposes of this calculation, sustaining capital expenditures for each period include the impact of accruals.

(5) See Note 8 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.

(6) At the sole discretion of Enterprise GP, cash retained by the partnership with respect to each of these periods 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.

(7) Distribution coverage ratio is 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.

Designated Units Issued in Connection with Holdings Merger
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 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 by us to this privately held affiliate of EPCO during 2015 excluded 35,380,000 Designated Units. The temporary distribution waiver expired at the end of calendar year 2015; therefore, distributions to be paid, if any, during calendar year 2016 will include all common units owned by the privately held affiliates of EPCO.

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 network 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. Although our focus in recent years has been on expansion through growth capital projects, management continues to analyze potential business combinations, asset acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In light of current business conditions, we expect that these opportunities will increase.

We completed approximately $300 million of growth capital projects in the first quarter of 2016 and are on schedule to complete and begin commercial service on another $2.2 billion of growth capital projects during the remainder of 2016. These projects include two natural gas processing plants and related infrastructure serving the Permian Basin (including our South Eddy facility which was commissioned in early May 2016); our ethane export terminal on the Houston Ship Channel; and additional crude oil storage infrastructure in the Houston and Beaumont areas. We have a total of $4.2 billion of growth projects scheduled to be completed in 2017 and 2018, with our two largest projects being the PDH facility and Midland-to-Sealy Pipeline.

We currently expect our total capital spending for the remainder of 2016 to approximate $3.1 billion, which includes the $1.0 billion final installment for EFS Midstream and approximately $215 million for sustaining capital expenditures. Our forecast of capital spending for the remainder of 2016 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, the issuance of additional equity and debt securities, and potential divestitures. We may revise our forecast of capital spending due to factors beyond our control, such as adverse economic conditions, weather related issues and changes in supplier prices. Furthermore, our forecast of capital spending may change as a result of decisions made by management at a later date, which may include unforeseen acquisition opportunities.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a significant 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 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.

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

	For the Three Months Ended March 31,	
	2016	2015
Step 2 of Oiltanking acquisition:		
Equity instruments (36,827,517 common units of Enterprise) (1)	$ --	$ 1,408.7
Capital spending for property, plant and equipment, net: (2)		
Growth capital projects (3)	920.6	733.7
Sustaining capital projects (4)	74.4	59.5
Investments in unconsolidated affiliates	70.4	68.3
Total capital spending	$ 1,065.4	$ 2,270.2

(1) Amount represents non-cash equity consideration we issued to complete Step 2 of the Oiltanking acquisition.
(2) 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 $12.2 million and $19.6 million for the three months ended March 31, 2016 and 2015, respectively. Growth and sustaining capital amounts presented in the table above are presented net of related contributions in aid of construction costs.
(3) 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.
(4) 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.

Fluctuations in our spending for growth capital projects and investments in unconsolidated affiliates are explained in large part by increases or decreases in spending on major expansion projects. Our most significant growth capital expenditures for the three months ended March 31, 2016 involved projects at our Mont Belvieu complex. Fluctuations in spending for sustaining capital projects are explained in large part by the timing and cost of pipeline integrity and similar projects.

Comparison of First Quarter of 2016 with First Quarter of 2015

In total, capital spending for property, plant and equipment increased $201.8 million quarter-to-quarter primarily due to higher growth capital spending during the three months ended March 31, 2016. Growth capital spending at our Mont Belvieu complex increased $91.5 million quarter-to-quarter primarily due to ongoing construction of our PDH facility. Currently, we expect construction of the PDH facility to be completed in the first quarter of 2017 with commercial operations expected to begin in the second quarter of 2017. Growth capital spending on our natural gas processing and related pipeline projects in the Delaware Basin increased a combined $50.8 million quarter-to-quarter. Our South Eddy natural gas processing plant and related pipeline infrastructure began operations in May 2016. Growth capital spending at our natural gas processing plants in South Louisiana increased $34.5 million quarter-to-quarter.

Growth capital spending on our Midland-to-Sealy and Rancho II pipelines increased a net $43.5 million quarter-to-quarter. With completion expected in mid-2018, the Midland-to-Sealy Pipeline will transport crude oil from Midland, Texas to our storage facility in Sealy, Texas. Volumes arriving in Sealy would then be transported to our ECHO terminal using our Rancho II pipeline. The Rancho II pipeline, a component of our South Texas Crude Oil Pipeline System, was completed and entered commercial service in September 2015. Lastly, growth capital spending for the expansion of crude oil terminal assets at our ECHO, Houston Ship Channel and Beaumont Marine West terminals increased a net $31.3 million quarter-to-quarter.

Growth capital spending at our Houston Ship Channel LPG and ethane export facilities decreased a combined $88.5 million quarter-to-quarter. We completed two expansion projects during 2015 at our Houston Ship Channel LPG export facility that increased our ability to load cargos of fully refrigerated, low-ethane propane to approximately 16.0 MMBbls per month. Work also continues at our Houston Ship Channel ethane export facility, which we expect to begin operations in the third quarter of 2016.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2015 Form 10-K. The following types of 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 9 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 for the periods indicated (dollars in millions):

	For the Three Months Ended March 31,	
	2016	**2015**
Total segment gross operating margin	$ 1,318.5	$ 1,334.4
Adjustments to reconcile total segment gross operating margin to operating income:		
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(358.2)	(345.3)
Subtract impairment charges not reflected in gross operating margin	(1.7)	(33.3)
Add net gains or subtract net losses attributable to asset sales not reflected in gross operating margin	(4.9)	0.1
Subtract non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	(7.1)	(30.7)
Add subsequent recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	12.9	20.1
Subtract general and administrative costs not reflected in gross operating margin	(43.9)	(49.3)
Operating income	$ 915.6	$ 896.0

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

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

	For the Three Months Ended March 31,	
	2016	**2015**
Distributable cash flow	$ 1,053.6	$ 1,029.7
Adjustments to reconcile distributable cash flow to net cash flows provided by operating activities:		
Add sustaining capital expenditures reflected in distributable cash flow	59.3	50.7
Subtract cash proceeds from asset sales reflected in distributable cash flow	(13.4)	(0.5)
Net effect of changes in operating accounts not reflected in distributable cash flow	(186.4)	(139.0)
Other, net	(13.4)	13.1
Net cash flows provided by operating activities	$ 899.7	$ 954.0

Contractual Obligations
Our consolidated principal debt obligations at March 31, 2016 were approximately $22.95 billion compared to $22.74 billion at December 31, 2015. For information regarding the scheduled maturities of such debt, see "Liquidity and Capital Resources – Consolidated Debt" within this Part I, Item 2. See Note 7 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.

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 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

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

General

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.

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 2015 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 12 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.

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, petrochemicals and refined 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 March 31, 2016 (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)	32.7	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	6.5	n/a	Cash flow hedge
Octane enhancement:			
Forecasted sales of octane enhancement products (MMBbls)	1.0	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	7.2	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	8.9	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	58.3	0.5	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	66.3	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	1.8	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.5	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	5.1	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	13.1	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	20.3	n/a	Cash flow hedge
Crude oil inventory management activities (MMBbls)	0.2	n/a	Fair value hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (4,5)	80.9	7.4	Mark-to-market
NGL risk management activities (MMBbls) (5)	4.0	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	28.5	2.3	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 2017, December 2016 and March 2019, 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 51.0 Bcf and 2.1 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 March 31, 2016, 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 natural gas processing margins and (iii) hedging the fair value of commodity products held in inventory.

- The objective of our anticipated future commodity purchases and sales hedging program is to hedge the margins of certain transportation, storage, blending and operational activities by locking in purchase and sale prices 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 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 following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our natural gas marketing portfolio at the dates indicated (dollars in millions):

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2015**	**March 31, 2016**	**April 15, 2016**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ 0.1	$ (3.6)	$ (5.6)
Fair value assuming 10% increase in underlying commodity prices	*Liability*	(3.7)	(7.6)	(10.1)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	3.9	0.4	(1.0)

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

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2015**	**March 31, 2016**	**April 15, 2016**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ 69.6	$ (58.6)	$ (76.4)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	41.7	(101.7)	(123.5)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	97.4	(15.6)	(29.4)

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

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2015**	**March 31, 2016**	**April 15, 2016**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ 42.9	$ 4.0	$ (16.9)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	25.9	(39.1)	(63.1)
Fair value assuming 10% decrease in underlying commodity prices	*Asset*	60.0	47.0	29.4

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 may be used in controlling our overall cost of capital associated with such borrowings. The composition of our derivative instrument portfolios may change 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 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 March 31, 2016 (dollars in millions):

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes OO	10 fixed-to-floating swaps	$750.0	5/2015 to 5/2018	1.65% to 1.10%	Fair value hedge

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

		Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2015	March 31, 2016	April 15, 2016
Fair value assuming no change in underlying interest rates	*Asset (Liability)*	$ (0.5)	$ 6.8	$ 7.0
Fair value assuming 10% increase in underlying interest rates	*Asset (Liability)*	(2.6)	5.5	5.7
Fair value assuming 10% decrease in underlying interest rates	*Asset*	1.7	8.1	8.3

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 (i) A. James Teague, our general partner's Chief Executive Officer, (ii) W. Randall Fowler, our general partner's President, and (iii) Bryan F. Bulawa, our general partner's Chief Financial Officer, of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Mr. Teague is our principal executive officer and Messrs. Fowler and Bulawa represent our principal financial officers. Based on this evaluation, as of the end of the period covered by this quarterly report, Messrs. Teague, Fowler and Bulawa 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 first quarter of 2016, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Section 302 and 906 Certifications

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

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings*****.**

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

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

Item 1A. ***Risk Factors*****.**

An investment in our securities involves certain risks. Security holders and potential investors in our securities should carefully consider the risks described under "Risk Factors" set forth in Part I, Item 1A of our 2015 Form 10-K, in addition to other information in such annual report. The risk factors set forth in our 2015 Form 10-K are important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

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

The following table summarizes our repurchase activity during the three months ended March 31, 2016:

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 2016 (1)	388,396	$ 22.96	--	--

(1) Of the 1,167,578 restricted common units that vested in February 2016 and converted to common units, 388,396 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.***

Disclosure Under Section 13(r) of the Securities Exchange Act of 1934

Under Section 13(r) of the Securities Exchange Act of 1934, as amended by the Iran Threat Reduction and Syria Human Rights Act of 2012, issuers are required to include certain disclosures in their periodic reports if they or any of their “affiliates” (as defined in Rule 12b-2 thereunder) have knowingly engaged in certain specified activities relating to Iran. Disclosure is required even where the activities are conducted outside the U.S. by non-U.S. affiliates in compliance with applicable law, and even if the activities are not covered or prohibited by U.S. law.

Dr. F. Christian Flach was named a director of our general partner in October 2014 in connection with the acquisition of Oiltanking. Dr. Flach is also a managing director of Oiltanking GmbH, which maintains a joint venture interest in Oiltanking Odfjell GmbH, which in turn owns a joint venture interest in the Exir Chemical Terminal (“ECT”) in Iran. This interest results from an investment dating back to 2002. Oiltanking GmbH currently has the contractual right to vote for the appointment of one member of ECT’s three-member board. Oiltanking GmbH provides no goods, services, technology, information or support to ECT and plays no role in the management or day-to-day operations of ECT.

Among other activities, ECT provides transit storage for naphtha originating in Iraq en route to Oman for a customer in the United Arab Emirates. ECT does not import or handle any products originated from Iran that are regulated under U.S., European Union or United Nations sanctions laws. ECT pays routine and standard charges (i) to the Petrochemical Special Economic Zone Organization (“Petzone”) for the use of pipelines and (ii) to Terminals and Tanks Petrochemical Co. (“TTPC”), which operates the berth. Petzone and TTPC are subsidiaries of the National Petrochemical Company, which is owned and controlled by the Government of Iran. As Oiltanking GmbH has no direct involvement in the day-to-day operations of ECT, we have no information regarding ECT’s intent to continue or not continue making the payments described above.

Oiltanking GmbH maintains an internal compliance program to ensure compliance with all applicable sanctions regimes, including sanctions laws maintained by the U.S., European Union and United Nations. Although the existence of the routine payments described above may be reportable under Section 13(r), Oiltanking GmbH has informed us that neither it, nor any of its subsidiaries or affiliates, has engaged in any conduct that would be sanctionable under any of these legal regimes.

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).
2.13	Agreement and Plan of Merger, dated as of November 11, 2014, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPOT MergerCo LLC, Oiltanking Partners, L.P. and OTLP GP, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed November 12, 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	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).
4.4	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).
4.5	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).
4.6	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).
4.7	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).
4.8	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).
4.9	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).
4.10	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).
4.11	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).
4.12	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).

4.13	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).
4.14	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).
4.15	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).
4.16	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).
4.17	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).
4.18	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).
4.19	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).
4.20	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).
4.21	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).
4.22	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).
4.23	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).
4.24	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).
4.25	Twenty-Seventh Supplemental Indenture, dated as of May 7, 2015, 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 7, 2015).
4.26	Twenty-Eighth Supplemental Indenture, dated as of April 13, 2016, 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 April 13, 2016).

4.27	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).
4.28	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).
4.29	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).
4.30	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).
4.31	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.32	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).
4.33	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).
4.34	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).
4.35	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).
4.36	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).
4.37	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).
4.38	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).
4.39	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).
4.40	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).
4.41	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).
4.42	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).
4.43	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).
4.44	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).
4.45	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).

4.46	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 4.25 to Form 10-Q filed May 10, 2012).
4.47	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).
4.48	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).
4.49	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).
4.50	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).
4.51	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).
4.52	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).
4.53	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).
4.54	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).
4.55	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).
4.56	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).
4.57	Form of Global Note representing $750.0 million principal amount of 1.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed May 7, 2015).
4.58	Form of Global Note representing $875.0 million principal amount of 3.70% Senior Notes due 2026 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed May 7, 2015).
4.59	Form of Global Note representing $875.0 million principal amount of 4.90% Senior Notes due 2046 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed May 7, 2015).
4.60	Form of Global Note representing $575.0 million principal amount of 2.85% Senior Notes due 2021 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed April 13, 2016).
4.61	Form of Global Note representing $575.0 million principal amount of 3.95% Senior Notes due 2027 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed April 13, 2016).
4.62	Form of Global Note representing $100.0 million principal amount of 4.90% Senior Notes due 2046 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed April 13, 2016).
4.63	Replacement Capital Covenant, dated July 18, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed July 19, 2006).
4.64	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).

4.65 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).

4.66 Replacement Capital Covenant, dated October 27, 2009, executed by 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).

4.67 Amendment to Replacement Capital Covenants, dated May 6, 2015, executed by Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.59 to Form 10-Q filed May 8, 2015).

4.68 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).

4.69 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).

4.70 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).

4.71 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).

4.72 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).

4.73 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).

4.74 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).

4.75 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).

4.76 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).
4.77	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).
4.78	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.79	Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.80	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed on March 1, 2010).
4.81	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***	EPD PubCo Unit I L.P. Agreement of Limited Partnership dated February 22, 2016 (incorporated by reference to Exhibit 10.1 to Form 8-K filed on February 26, 2016).
10.2***	EPD PubCo Unit II L.P. Agreement of Limited Partnership dated February 22, 2016 (incorporated by reference to Exhibit 10.2 to Form 8-K filed on February 26, 2016).
10.3***	EPD PrivCo Unit I L.P. Agreement of Limited Partnership dated February 22, 2016 (incorporated by reference to Exhibit 10.3 to Form 8-K filed on February 26, 2016).
12.1#	Computation of ratio of earnings to fixed charges for the three months ended March 31, 2016 and each of the years ended December 31, 2015, 2014, 2013, 2012 and 2011.
31.1#	Sarbanes-Oxley Section 302 certification of A. James Teague for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the three months ended March 31, 2016.
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 three months ended March 31, 2016.
31.3#	Sarbanes-Oxley Section 302 certification of Bryan F. Bulawa for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the three months ended March 31, 2016.
32.1#	Sarbanes-Oxley Section 906 certification of A. James Teague for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the three months ended March 31, 2016.
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 three months ended March 31, 2016.
32.3#	Sarbanes-Oxley Section 906 certification of Bryan F. Bulawa for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the three months ended March 31, 2016.
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.
***	Identifies management contract and compensatory plan arrangements.
#	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 May 6, 2016.

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