UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2017

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, a smaller reporting company, or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth 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 ☐
Emerging growth company ☐	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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 2,152,702,622 common units of Enterprise Products Partners L.P. outstanding at the close of business on October 31, 2017. Our common units trade on the New York Stock Exchange under the ticker symbol "EPD."

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

Item 1. *Financial Statements*.

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

	September 30, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 32.9	$ 63.1
Restricted cash	66.8	354.5
Accounts receivable – trade, net of allowance for doubtful accounts of $12.3 at September 30, 2017 and $11.3 at December 31, 2016	3,392.2	3,329.5
Accounts receivable – related parties	3.2	1.1
Inventories	1,983.2	1,770.5
Derivative assets (see Note 12)	180.2	541.4
Prepaid and other current assets	372.6	468.1
Total current assets	6,031.1	6,528.2
Property, plant and equipment, net	34,979.3	33,292.5
Investments in unconsolidated affiliates	2,660.2	2,677.3
Intangible assets, net of accumulated amortization of $1,525.3 at September 30, 2017 and $1,403.1 at December 31, 2016 (see Note 6)	3,739.8	3,864.1
Goodwill (see Note 6)	5,745.2	5,745.2
Other assets	145.0	86.7
Total assets	$ 53,300.6	$ 52,194.0
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 7)	$ 3,009.0	$ 2,576.8
Accounts payable – trade	720.3	397.7
Accounts payable – related parties	109.0	105.1
Accrued product payables	3,760.2	3,613.7
Accrued interest	206.5	340.8
Derivative liabilities (see Note 12)	225.3	737.7
Other current liabilities	408.4	478.7
Total current liabilities	8,438.7	8,250.5
Long-term debt (see Note 7)	21,710.9	21,120.9
Deferred tax liabilities	53.7	52.7
Other long-term liabilities	548.4	503.9
Commitments and contingencies (see Note 14)		
Equity: (see Note 8)		
Partners' equity:		
Limited partners:		
Common units (2,152,702,622 units outstanding at September 30, 2017 and 2,117,588,414 units outstanding at December 31, 2016)	22,637.2	22,327.0
Accumulated other comprehensive loss	(306.6)	(280.0)
Total partners' equity	22,330.6	22,047.0
Noncontrolling interests	218.3	219.0
Total equity	22,548.9	22,266.0
Total liabilities and equity	$ 53,300.6	$ 52,194.0

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Revenues:				
Third parties	$ 6,874.4	$ 5,904.7	$ 20,781.7	$ 16,499.0
Related parties	12.5	15.7	33.2	44.5
Total revenues (see Note 9)	6,886.9	5,920.4	20,814.9	16,543.5
Costs and expenses:				
Operating costs and expenses:				
Third parties	5,773.8	4,781.2	17,313.0	13,199.4
Related parties	306.0	284.5	830.2	835.4
Total operating costs and expenses	6,079.8	5,065.7	18,143.2	14,034.8
General and administrative costs:				
Third parties	11.0	15.0	47.7	35.9
Related parties	30.3	27.0	89.7	85.1
Total general and administrative costs	41.3	42.0	137.4	121.0
Total costs and expenses (see Note 9)	6,121.1	5,107.7	18,280.6	14,155.8
Equity in income of unconsolidated affiliates	113.4	92.3	315.2	269.8
Operating income	879.2	905.0	2,849.5	2,657.5
Other income (expense):				
Interest expense	(243.9)	(250.9)	(739.0)	(735.6)
Change in fair market value of Liquidity Option Agreement (see Note 14)	(8.9)	(6.9)	(33.0)	(28.0)
Other, net	0.3	0.7	0.9	2.5
Total other expense, net	(252.5)	(257.1)	(771.1)	(761.1)
Income before income taxes	626.7	647.9	2,078.4	1,896.4
Provision for income taxes	(5.4)	(4.8)	(20.1)	(13.1)
Net income	621.3	643.1	2,058.3	1,883.3
Net income attributable to noncontrolling interests	(10.4)	(8.5)	(33.0)	(29.0)
Net income attributable to limited partners	$ 610.9	$ 634.6	$ 2,025.3	$ 1,854.3
Earnings per unit: (see Note 10)				
Basic earnings per unit	$ 0.28	$ 0.30	$ 0.94	$ 0.89
Diluted earnings per unit	$ 0.28	$ 0.30	$ 0.94	$ 0.89

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 September 30,		For the Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
Net income	$ 621.3	$ 643.1	$ 2,058.3	$ 1,883.3
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instruments:				
Changes in fair value of cash flow hedges	(177.8)	22.7	(2.6)	(52.2)
Reclassification of gains to net income	(10.1)	(26.9)	(49.0)	(48.7)
Interest rate derivative instruments:				
Changes in fair value of cash flow hedges	(0.3)	(6.9)	(4.8)	(16.3)
Reclassification of losses to net income	10.3	9.4	29.9	27.8
Total cash flow hedges	(177.9)	(1.7)	(26.5)	(89.4)
Other	--	--	(0.1)	(0.1)
Total other comprehensive loss	(177.9)	(1.7)	(26.6)	(89.5)
Comprehensive income	443.4	641.4	2,031.7	1,793.8
Comprehensive income attributable to noncontrolling interests	(10.4)	(8.5)	(33.0)	(29.0)
Comprehensive income attributable to limited partners	$ 433.0	$ 632.9	$ 1,998.7	$ 1,764.8

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Nine Months Ended September 30,	
	2017	**2016**
Operating activities:		
Net income	$ 2,058.3	$ 1,883.3
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	1,221.4	1,155.3
Asset impairment and related charges (see Note 12)	35.2	29.1
Equity in income of unconsolidated affiliates	(315.2)	(269.8)
Distributions received on earnings from unconsolidated affiliates	316.2	281.6
Net gains attributable to asset sales	(1.1)	(2.3)
Deferred income tax expense	1.1	5.3
Change in fair market value of derivative instruments	(14.2)	42.1
Change in fair market value of Liquidity Option Agreement	33.0	28.0
Net effect of changes in operating accounts (see Note 15)	(512.1)	(489.7)
Other operating activities	(2.7)	(3.9)
Net cash flows provided by operating activities	2,819.9	2,659.0
Investing activities:		
Capital expenditures	(2,154.4)	(2,443.9)
Contributions in aid of construction costs	36.2	34.1
Decrease (increase) in restricted cash (see Note 2)	287.7	(261.4)
Cash used for business combinations, net of cash received (see Note 4)	(198.7)	(1,000.0)
Investments in unconsolidated affiliates	(32.8)	(119.9)
Distributions received for return of capital from unconsolidated affiliates	36.8	51.9
Proceeds from asset sales	6.2	43.9
Other investing activities	2.8	(0.4)
Cash used in investing activities	(2,016.2)	(3,695.7)
Financing activities:		
Borrowings under debt agreements	53,150.4	50,183.8
Repayments of debt	(52,133.2)	(48,776.5)
Debt issuance costs	(24.0)	(10.5)
Monetization of interest rate derivative instruments	30.6	--
Cash distributions paid to limited partners (see Note 8)	(2,660.4)	(2,448.3)
Cash payments made in connection with distribution equivalent rights	(11.2)	(8.5)
Cash distributions paid to noncontrolling interests	(35.4)	(35.7)
Cash contributions from noncontrolling interests	0.4	20.1
Net cash proceeds from the issuance of common units	877.2	2,170.4
Other financing activities	(28.3)	(20.0)
Cash provided by (used in) financing activities	(833.9)	1,074.8
Net change in cash and cash equivalents	(30.2)	38.1
Cash and cash equivalents, January 1	63.1	19.0
Cash and cash equivalents, September 30	$ 32.9	$ 57.1

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, January 1, 2017	$ 22,327.0	$ (280.0)	$ 219.0	$ 22,266.0
Net income	2,025.3	--	33.0	2,058.3
Cash distributions paid to limited partners	(2,660.4)	--	--	(2,660.4)
Cash payments made in connection with distribution equivalent rights	(11.2)	--	--	(11.2)
Cash distributions paid to noncontrolling interests	--	--	(35.4)	(35.4)
Cash contributions from noncontrolling interests	--	--	0.4	0.4
Net cash proceeds from the issuance of common units	877.2	--	--	877.2
Common units issued in connection with employee compensation	33.7	--	--	33.7
Amortization of fair value of equity-based awards	74.1	--	--	74.1
Cash flow hedges	--	(26.5)	--	(26.5)
Other	(28.5)	(0.1)	1.3	(27.3)
Balance, September 30, 2017	$ 22,637.2	$ (306.6)	$ 218.3	$ 22,548.9

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, January 1, 2016	$ 20,514.3	$ (219.2)	$ 206.0	$ 20,501.1
Net income	1,854.3	--	29.0	1,883.3
Cash distributions paid to limited partners	(2,448.3)	--	--	(2,448.3)
Cash payments made in connection with distribution equivalent rights	(8.5)	--	--	(8.5)
Cash distributions paid to noncontrolling interests	--	--	(35.7)	(35.7)
Cash contributions from noncontrolling interests	--	--	20.1	20.1
Net cash proceeds from the issuance of common units	2,170.4	--	--	2,170.4
Amortization of fair value of equity-based awards	67.7	--	--	67.7
Cash flow hedges	--	(89.4)	--	(89.4)
Other	(22.0)	(0.1)	0.1	(22.0)
Balance, September 30, 2016	$ 22,127.9	$ (308.7)	$ 219.5	$ 22,038.7

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 32 percent of our limited partner interests at September 30, 2017.

References to "Oiltanking acquisition" mean the two-step acquisition of Oiltanking Partners, L.P. and its general partner that was completed in February 2015.

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

Note 1. Partnership Operations, 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 liquids ("NGLs") related businesses of EPCO and are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products.

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and 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 export and import terminals (including those used to export liquefied petroleum gases, or "LPG," and ethane); crude oil gathering, transportation, storage, and export and import terminals; petrochemical and refined products transportation, storage, export and import 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 50,000 miles of pipelines; 260 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 percent 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 operations are reported under four business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services and (iv) Petrochemical & Refined Products Services. See Note 9 for information regarding our business segments.

Note 2. General Accounting and Disclosure Matters

Our results of operations for the nine months ended September 30, 2017 are not necessarily indicative of results expected for the full year of 2017. 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, 2016 (the "2016 Form 10-K") filed with the SEC on February 24, 2017.

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, 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.

Recent Accounting Developments

Revenue Recognition. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Codification 606, *Revenues from Contracts with Customers* ("ASC 606"). The new accounting standard, along with its related amendments, replaces the current rules-based U.S. GAAP governing revenue recognition with a principles-based approach. We will adopt the new standard on January 1, 2018 using a modified retrospective approach, which requires us to apply the new revenue standard to (i) all new revenue contracts entered into after January 1, 2018 and (ii) all existing revenue contracts as of January 1, 2018 through a cumulative adjustment to equity, if necessary. In accordance with this approach, our consolidated revenues for periods prior to January 1, 2018 will not be revised.

The core principle in the new guidance is that a company should recognize revenue in a manner that fairly depicts the transfer of goods or services to customers in amounts that reflect the consideration the company expects to receive for those goods or services. In order to apply this core principle, companies will apply the following five steps in determining the amount of revenues to recognize: (i) identify the contract; (ii) identify the performance obligations in the contract; (iii) determine the transaction price; (iv) allocate the transaction price to the performance obligations in the contract; and (v) recognize revenue when (or as) the performance obligation is satisfied. Each of these steps involves management's judgment and an analysis of the contract's material terms and conditions.

Our implementation activities related to ASC 606 are nearly complete. For the vast majority of our businesses, we will not have any material differences in the amount or timing of revenues once we adopt ASC 606.

However, based on guidance in ASC 606 applicable to non-cash consideration, we will start recognizing revenue in connection with equity NGL volumes we receive as consideration for providing processing services under percent of liquids and similar arrangements. The value assigned to this non-cash consideration and related inventory will be based on the fair value of NGLs we are entitled to at the time the processing services are performed. An additional revenue stream, along with the related cost of sales, would be recognized in connection with the ultimate sale of the NGL products derived from the NGLs acquired as a fee for service. Under current accounting practice, we only recognize revenue from the downstream sale of NGL products and do not record service revenue. Based on initial estimates, the changes required by ASC 606 are expected to result in less than a 5 percent increase in our total consolidated revenues.

Given the rapid turnover of our inventories of NGL products each month, we do not expect a significant change in our gross operating margin from natural gas processing and related NGL marketing activities as a result of the changes required by ASC 606. The additional revenue stream recognized in connection with receipt of the equity NGLs will be offset by an equal cost of sales amount when the associated NGL products are sold, which is expected to typically be completed in the same accounting period.

As a result of adopting the new standard, there will be significant changes to our disclosures based on the additional requirements prescribed by ASC 606. These new disclosures include information regarding the significant judgments used in evaluating when and how revenue is (or will be) recognized and data related to contract assets and liabilities. Additionally, we are revising our business processes, systems and controls to ensure the accuracy and timeliness of the recognition and disclosure requirements under the new revenue guidance.

Leases. In February 2016, the FASB issued ASC 842, *Leases* ("ASC 842"), which requires substantially all leases (with the exception of leases with a term of one year or less) to be recorded on the balance sheet using a method referred to as the right-of-use ("ROU") asset approach. We plan to adopt the new standard on January 1, 2019 using a modified retrospective approach.

The new standard introduces two lease accounting models, which result in a lease being classified as either a "finance" or "operating" lease on the basis of whether the lessee effectively obtains control of the underlying asset during the lease term. A lease would be classified as a finance lease if it meets one of five classification criteria, four of which are generally consistent with current lease accounting guidance. By default, a lease that does not meet the criteria to be classified as a finance lease will be deemed an operating lease. Regardless of classification, the initial measurement of both lease types will result in the balance sheet recognition of a ROU asset representing a company's right to use the underlying asset for a specified period of time and a corresponding lease liability. The lease liability will be recognized at the present value of the future lease payments, and the ROU asset will equal the lease liability adjusted for any prepaid rent, lease incentives provided by the lessor, and any indirect costs.

The subsequent measurement of each type of lease varies. Leases classified as a finance lease will be accounted for using the effective interest method. Under this approach, a lessee will amortize the ROU asset (generally on a straight-line basis in a manner similar to depreciation) and the discount on the lease liability (as a component of interest expense). Leases classified as an operating lease will result in the recognition of a single lease expense amount that is recorded on a straight-line basis (or another systematic basis, if more appropriate).

We have started the process of reviewing our lease agreements in light of the new guidance. Although we are in the early stages of our ASC 842 implementation project, we anticipate that this new lease guidance will cause significant changes to the way leases are recorded, presented and disclosed in our consolidated financial statements.

Derivative Instruments. In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*, which amends and simplifies existing guidance in order to allow companies to more accurately present the economic effects of risk management activities in the financial statements. As a result, companies will record the entire change in fair value of cash flow hedges to other comprehensive income until the hedged item impacts earnings and present the earnings effect of cash flow and fair value hedges in the same income statement line item that is used to present the earnings impact of the hedged item. Companies will no longer be required to separately measure and disclose the effect of hedge ineffectiveness, but will need to include tabular disclosures related to income statement effect of cash flow and fair value hedges and cumulative basis adjustments for fair value hedges. We are currently evaluating the impact of this guidance on our consolidated financial statements and the timing of our planned adoption.

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 margin requirements change.

At September 30, 2017 and December 31, 2016, our restricted cash amounts were $66.8 million and $354.5 million, respectively. The balance of restricted cash decreased since December 31, 2016 primarily due to the settlement of derivative instruments related to contango positions during 2017. See Note 12 for information regarding our derivative instruments and hedging activities.

Impact of ASU 2016-18. The FASB recently issued an amendment, ASU 2016-18, to Topic 230, *Statement of Cash Flows*, that standardizes the presentation of transfers to and from restricted cash within the cash flow statement. As a result, the cash flow statement will present changes in total cash amounts, regardless of whether the cash balances are restricted or unrestricted. The new guidance does not affect the separate presentation of restricted and unrestricted (i.e., cash and cash equivalents) amounts on the balance sheet. Furthermore, this change in financial statement presentation will not impact our consolidated liquidity.

We intend to early adopt the new cash flow statement guidance on December 31, 2017 by retrospectively adjusting our consolidated cash flow statements to eliminate the presentation of cash inflows and outflows associated with restricted cash that were historically shown in the investing activities section.

Note 3. Inventories

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

	September 30, 2017	December 31, 2016
NGLs	$ 1,527.8	$ 1,156.1
Petrochemicals and refined products	223.4	220.7
Crude oil	211.9	360.0
Natural gas	20.1	33.7
Total	$ 1,983.2	$ 1,770.5

Due to fluctuating commodity prices, we recognize lower of cost or net realizable value 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 net realizable value adjustments for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Cost of sales (1)	$ 5,049.6	$ 4,088.6	$ 15,116.4	$ 11,135.6
Lower of cost or net realizable value adjustments within cost of sales	1.7	1.5	7.7	7.6

(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	September 30, 2017	December 31, 2016
Plants, pipelines and facilities (1)	3-45 (5)	$ 35,970.8	$ 35,124.6
Underground and other storage facilities (2)	5-40 (6)	3,427.0	3,326.9
Transportation equipment (3)	3-10	174.3	165.8
Marine vessels (4)	15-30	802.4	800.7
Land		271.1	264.6
Construction in progress		4,942.0	3,320.7
Total		45,587.6	43,003.3
Less accumulated depreciation		10,608.3	9,710.8
Property, plant and equipment, net		$ 34,979.3	$ 33,292.5

(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 September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Depreciation expense (1)	$ 327.5	$ 309.4	$ 966.1	$ 903.5
Capitalized interest (2)	53.6	38.9	137.7	127.8

(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.

Azure Acquisition

In April 2017, we closed the acquisition of a midstream energy business from Azure Midstream Partners, LP and its operating subsidiaries (collectively, "Azure") for $191.4 million in cash. The acquired business assets, which are located primarily in East Texas, include over 730 miles of natural gas gathering pipelines and two natural gas processing facilities with an aggregate processing capacity of 130 million cubic feet per day. The acquired business serves production from the Haynesville Shale and Bossier, Cotton Valley and Travis Peak formations.

The financial results of the acquired business are reflected in our consolidated results from April 30, 2017, which was the effective date of the Azure acquisition. On a historical pro forma consolidated basis, our revenues, costs and expenses, operating income, net income attributable to Enterprise Products Partners L.P., and earnings per unit amounts for the three and nine months ended September 30, 2016 and 2017 would not have differed materially from those we actually reported had the Azure acquisition been completed on January 1, 2016 rather than April 30, 2017.

The following table presents the preliminary fair value allocation of assets acquired and liabilities assumed in the Azure acquisition at April 30, 2017. The allocation remains provisional due to ongoing efforts to clarify certain environmental liabilities (estimated at $2.2 million), which are expected to be resolved by December 31, 2017.

Assets acquired in business combination:	
Current assets	$ 3.1
Property, plant and equipment	194.2
Total assets acquired	197.3
Liabilities assumed in business combination:	
Current liabilities	1.4
Long-term liabilities	4.5
Total liabilities assumed	5.9
Cash used for Azure acquisition	$ 191.4

The contribution of this newly acquired business to our consolidated revenues and net income was not material for the three and nine months ended September 30, 2017.

Final Payment to Acquire EFS Midstream in July 2016

We acquired EFS Midstream in July 2015 for approximately $2.1 billion in cash, which was payable in two installments. The initial payment of $1.1 billion was paid at closing in July 2015. The second and final installment of $1.0 billion was paid in July 2016.

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 September 30, 2017 and December 31, 2016 includes $41.3 million and $44.9 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 January 1, 2017:

ARO liability balance, January 1, 2017	$	85.4
Liabilities incurred		4.7
Liabilities settled		(2.0)
Revisions in estimated cash flows		(5.6)
Accretion expense		4.1
ARO liability balance, September 30, 2017	$	86.6

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 September 30, 2017	September 30, 2017	December 31, 2016
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 25.9	$ 24.8
K/D/S Promix, L.L.C.	50%	32.0	33.7
Baton Rouge Fractionators LLC	32.2%	17.3	17.3
Skelly-Belvieu Pipeline Company, L.L.C.	50%	37.2	38.9
Texas Express Pipeline LLC	35%	321.1	331.9
Texas Express Gathering LLC	45%	36.2	35.8
Front Range Pipeline LLC	33.3%	165.8	165.4
Delaware Basin Gas Processing LLC	50%	107.3	102.6
Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC	50%	1,378.4	1,393.8
Eagle Ford Pipeline LLC	50%	384.5	377.9
Eagle Ford Terminals Corpus Christi LLC	50%	66.9	52.9
Natural Gas Pipelines & Services:			
White River Hub, LLC	50%	21.2	21.7
Petrochemical & Refined Products Services:			
Centennial Pipeline LLC	50%	61.4	62.3
Other	Various	5.0	18.3
Total investments in unconsolidated affiliates		$ 2,660.2	$ 2,677.3

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
NGL Pipelines & Services	$ 18.8	$ 15.9	$ 53.3	$ 45.0
Crude Oil Pipelines & Services	95.9	78.4	266.3	234.3
Natural Gas Pipelines & Services	0.9	1.0	2.8	2.9
Petrochemical & Refined Products Services	(2.2)	(3.0)	(7.2)	(12.4)
Total	$ 113.4	$ 92.3	$ 315.2	$ 269.8

Excess Cost

On occasion, the price we pay to acquire an ownership interest in a company exceeds the underlying carrying value of the capital accounts we acquire. These excess cost amounts are attributable to the fair value of the underlying tangible assets of these entities exceeding their respective book carrying values at the time of our acquisition of ownership interests in these entities. We amortize such excess cost amounts as a reduction to equity earnings in a manner similar to depreciation.

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

	September 30, 2017	December 31, 2016
NGL Pipelines & Services	$ 23.2	$ 24.1
Crude Oil Pipelines & Services	18.4	19.0
Petrochemical & Refined Products Services	1.8	2.1
Total	$ 43.4	$ 45.2

Amortization of excess cost amounts were \$0.6 million and \$0.5 million for the three months ended September 30, 2017 and 2016, respectively. For the nine months ended September 30, 2017 and 2016, amortization of excess costs amounts were \$1.6 million and \$1.6 million, 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 percent basis):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Income Statement Data:				
Revenues	$ 401.6	$ 328.9	$ 1,116.7	$ 991.9
Operating income	249.3	193.6	682.8	589.0
Net income	247.5	192.0	688.0	585.5

Note 6. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	September 30, 2017			December 31, 2016		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 447.4	$ (183.8)	$ 263.6	$ 447.4	$ (172.7)	$ 274.7
Contract-based intangibles	279.2	(215.1)	64.1	279.9	(204.4)	75.5
Segment total	726.6	(398.9)	327.7	727.3	(377.1)	350.2
Crude Oil Pipelines & Services:						
Customer relationship intangibles	2,203.5	(114.7)	2,088.8	2,204.4	(84.5)	2,119.9
Contract-based intangibles	281.0	(158.8)	122.2	281.0	(121.9)	159.1
Segment total	2,484.5	(273.5)	2,211.0	2,485.4	(206.4)	2,279.0
Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,350.3	(409.5)	940.8	1,350.3	(390.0)	960.3
Contract-based intangibles	464.7	(377.3)	87.4	464.7	(370.5)	94.2
Segment total	1,815.0	(786.8)	1,028.2	1,815.0	(760.5)	1,054.5
Petrochemical & Refined Products Services:						
Customer relationship intangibles	185.5	(48.4)	137.1	185.5	(43.9)	141.6
Contract-based intangibles	53.5	(17.7)	35.8	54.0	(15.2)	38.8
Segment total	239.0	(66.1)	172.9	239.5	(59.1)	180.4
Total intangible assets	$ 5,265.1	$ (1,525.3)	$ 3,739.8	$ 5,267.2	$ (1,403.1)	$ 3,864.1

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
NGL Pipelines & Services	$ 7.2	$ 7.6	$ 21.8	$ 23.1
Crude Oil Pipelines & Services	22.6	23.2	68.0	75.6
Natural Gas Pipelines & Services	9.3	8.1	26.3	25.0
Petrochemical & Refined Products Services	2.3	2.3	7.0	6.8
Total	$ 41.4	$ 41.2	$ 123.1	$ 130.5

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

Remainder of 2017	2018	2019	2020	2021
$ 40.8	$ 163.8	$ 157.7	$ 152.8	$ 163.2

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. There has been no change in our goodwill amounts since those reported in our 2016 Form 10-K.

Note 7. Debt Obligations

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

	September 30, 2017	December 31, 2016
EPO senior debt obligations:		
Commercial Paper Notes, variable-rates	$ 1,910.0	$ 1,777.2
Senior Notes L, 6.30% fixed-rate, due September 2017	--	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
364-Day Revolving Credit Agreement, variable-rate, due September 2018	--	--
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
Senior Notes RR, 2.85% fixed-rate, due April 2021	575.0	575.0
Senior Notes CC, 4.05% fixed-rate, due February 2022	650.0	650.0
Multi-Year Revolving Credit Facility, variable-rate, due September 2022	--	--
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 SS, 3.95% fixed-rate, due February 2027	575.0	575.0
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	975.0	975.0
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	21,760.0	22,427.2
EPO Junior Subordinated Notes A, 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
EPO Junior Subordinated Notes D, fixed/variable-rate, due August 2077 (4)	700.0	--
EPO Junior Subordinated Notes E, fixed/variable-rate, due August 2077 (5)	1,000.0	--
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2
Total principal amount of senior and junior debt obligations	24,934.4	23,901.6
Other, non-principal amounts	(214.5)	(203.9)
Less current maturities of debt	(3,009.0)	(2,576.8)
Total long-term debt	$ 21,710.9	$ 21,120.9

(1) Variable rate is reset quarterly and based on 3-month LIBOR plus 3.708%.
(2) Fixed rate of 7.000% through May 31, 2017; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 2.778%.
(3) Fixed rate of 7.034% through January 14, 2018; thereafter, the rate will be the greater of 7.034% or a variable rate reset quarterly and based on 3-month LIBOR plus 2.680%.
(4) Fixed rate of 4.875% through August 15, 2022; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 2.986%.
(5) Fixed rate of 5.250% through August 15, 2027; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 3.033%.

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt during the nine months ended September 30, 2017:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
Commercial Paper Notes	0.90% to 1.53%	1.28%
Prior Multi-Year Revolving Credit Facility (replaced in September 2017)	2.23%	2.23%
EPO Junior Subordinated Notes A	4.59% to 5.02%	4.83%
EPO Junior Subordinated Notes C	3.98% to 4.09%	4.01%

The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at September 30, 2017 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt					
	Total	Remainder of 2017	2018	2019	2020	2021	Thereafter
Commercial Paper Notes	$ 1,910.0	$ 1,910.0	$ --	$ --	$ --	$ --	$ --
Senior Notes	19,850.0	--	1,100.0	1,500.0	1,500.0	575.0	15,175.0
Junior Subordinated Notes	3,174.4	--	--	--	--	--	3,174.4
Total	$ 24,934.4	$ 1,910.0	$ 1,100.0	$ 1,500.0	$ 1,500.0	$ 575.0	$ 18,349.4

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 $1.7 Billion of Junior Subordinated Notes in August 2017

In August 2017, EPO issued a combined $1.7 billion in principal amount of junior subordinated notes in two series. The EPO Junior Subordinated Notes D ("Junior Notes D"), which were issued at $700 million principal amount in the aggregate, are redeemable at EPO's option, in whole or in part, on one or more occasions, on or after August 16, 2022 (the non-call 5 notes) at 100% of their principal amount, plus any accrued and unpaid interest. Junior Notes D bear interest at a fixed rate of 4.875% per year up to, but not including, August 16, 2022. From, and including August 16, 2022, Junior Notes D will bear interest at a floating rate based on a three-month LIBOR rate plus 2.986%, reset quarterly. Junior Notes D mature in August 2077.

The EPO Junior Subordinated Notes E ("Junior Notes E"), which were issued at $1.0 billion principal amount in the aggregate, are redeemable at EPO's option, in whole or in part, on one or more occasions, on or after August 16, 2027 (the non-call 10 notes) at 100% of their principal amount, plus any accrued and unpaid interest. Junior Notes E bear interest at a fixed rate of 5.25% per year up to, but not including, August 16, 2027. From, and including August 16, 2027, Junior Notes E will bear interest at a floating rate based on a three-month LIBOR rate plus 3.033%, reset quarterly. Junior Notes E also mature in August 2077.

Net proceeds from the issuance of Junior Notes D and E were used for (i) the temporary repayment of approximately $900 million of amounts then outstanding under EPO's commercial paper program and (ii) the repayment of $800 million in principal amount of Senior Notes L that matured in September 2017.

EPO's payment obligations under Junior Notes D and E are subordinated to the prior payment in full of all of its current and future senior indebtedness (as defined in the indenture governing such notes). Enterprise Products Partners L.P. guarantees repayment of amounts due under Junior Notes D and E on an unsecured and junior subordinated basis. The indenture governing these notes allows EPO to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. Subject to certain exceptions, during any period in which interest payments are deferred, neither we nor EPO can declare or pay any distributions with respect to, or redeem, purchase or acquire, any of our respective equity securities or make any payments on, or repay, repurchase or redeem, any of our respective debt securities that rank equally with or are subordinate to EPO's junior subordinated notes (or any related guarantee, as applicable). Each series of EPO's junior subordinated notes ranks equally with each other.

364-Day Revolving Credit Agreement
In September 2017, EPO entered into a 364-Day Revolving Credit Agreement that replaced its prior 364-day credit facility. The new 364-Day Revolving Credit Agreement matures in September 2018. There are currently no principal amounts outstanding under this revolving credit agreement.

Under the terms of the new 364-Day Revolving Credit Agreement, EPO may borrow up to $1.5 billion (which may be increased by up to $200 million to $1.7 billion at EPO’s election, provided certain conditions are met) at a variable interest rate for a term of 364 days, subject to the terms and conditions set forth therein. To the extent that principal amounts are outstanding at the maturity date, EPO may elect to have the entire principal balance then outstanding continued as a non-revolving term loan for a period of one additional year, payable in September 2019. Borrowings under this revolving credit agreement may be used for working capital, capital expenditures, acquisitions and general company purposes.

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

EPO’s obligations under the 364-Day Revolving Credit Agreement are not secured by any collateral; however, they are guaranteed by Enterprise Products Partners L.P.

Multi-Year Revolving Credit Facility
In September 2017, EPO entered into a revolving credit agreement that matures in September 2022 (the “Multi-Year Revolving Credit Facility”). This new facility replaced EPO’s prior multi-year revolving credit facility that was scheduled to mature in September 2020. There are currently no principal amounts outstanding under the new credit facility.

Under the terms of the new Multi-Year Revolving Credit Facility, EPO may borrow up to $4.0 billion (which may be increased by up to $500 million to $4.5 billion at EPO’s election, provided certain conditions are met) at a variable interest rate for a term of five years, subject to the terms and conditions set forth therein. Borrowings under this revolving credit facility may be used as a backstop for commercial paper and for working capital, capital expenditures, acquisitions and general company purposes.

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

EPO’s obligations under the Multi-Year Revolving Credit Facility are not secured by any collateral; however, they are guaranteed by Enterprise Products Partners L.P.

Lender Financial Covenants
We were in compliance with the financial covenants of our consolidated debt agreements at September 30, 2017.

Letters of Credit
At September 30, 2017, EPO had $66.4 million of letters of credit outstanding primarily related to our commodity hedging activities.

Note 8. Equity and Distributions

Partners' Equity

Partners' equity reflects the various classes of limited partner interests (i.e., common units, including restricted common units) outstanding. The following table summarizes changes in the number of our outstanding units from January 1, 2017 to September 30, 2017:

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
Number of units outstanding at January 1, 2017	2,116,906,120	682,294	2,117,588,414
Common units issued in connection with ATM program	21,807,726	--	21,807,726
Common units issued in connection with DRIP and EUPP	10,710,589	--	10,710,589
Common units issued in connection with the vesting of phantom unit awards	2,413,070	--	2,413,070
Common units issued in connection with the vesting of restricted common unit awards	679,370	(679,370)	--
Forfeiture of restricted common unit awards	--	(1,250)	(1,250)
Cancellation of treasury units acquired in connection with the vesting of equity-based awards	(1,006,715)	--	(1,006,715)
Common units issued in connection with employee compensation	1,176,103	--	1,176,103
Other	14,685	--	14,685
Number of units outstanding at September 30, 2017	2,152,700,948	1,674	2,152,702,622

The net cash proceeds we received from the issuance of common units during the nine months ended September 30, 2017 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and revolving credit facilities and for general company purposes.

We expect to issue additional equity and debt securities to assist us in meeting our future liquidity requirements, including those related to capital spending.

<u>*Universal shelf registration statement*</u>. We have a universal shelf registration statement (the "2016 Shelf") on file with the SEC. The 2016 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. EPO issued $1.7 billion of junior subordinated notes in August 2017 using this registration statement (see Note 7).

<u>*At-the-Market ("ATM") program*</u>. We have a registration statement on file with the SEC covering the issuance of up to $1.89 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings in connection with our 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 nine months ended September 30, 2017, we sold 21,807,726 common units under the ATM program for aggregate gross proceeds of $603.1 million. After taking into account applicable costs, our transactions under the ATM program resulted in aggregate net cash proceeds of $597.3 million during the nine months ended September 30, 2017.

During the nine months ended September 30, 2016, we issued 76,113,492 common units under this program for aggregate gross cash proceeds of $1.87 billion, resulting in total net cash proceeds of $1.85 billion. This includes 3,830,256 common units sold in January 2016 to a privately held affiliate of EPCO, which generated gross proceeds of $100 million.

After taking into account the aggregate sales price of common units sold under the ATM program through September 30, 2017, we have the capacity to issue additional common units under the ATM program up to an aggregate sales price of $838.6 million.

Distribution reinvestment plan. We also have registration statements on file with the SEC collectively authorizing the issuance of up to 240,000,000 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 10,345,655 common units under our DRIP during the nine months ended September 30, 2017, which generated net cash proceeds of $269.9 million. During the nine months ended September 30, 2016, we issued 12,946,724 common units under our DRIP, which generated net cash proceeds of $306.2 million. Privately held affiliates of EPCO reinvested $100 million through the DRIP during the nine months ended September 30, 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 September 30, 2017, we have the capacity to issue an additional 88,912,840 common units under this plan.

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 364,934 common units under our EUPP during the nine months ended September 30, 2017, which generated net cash proceeds of $10.0 million. During the nine months ended September 30, 2016, we issued 387,834 common units under our EUPP, which generated net cash proceeds of $9.8 million. After taking into account the number of common units issued under the EUPP through September 30, 2017, we may issue an additional 5,900,541 common units under this plan.

Common units issued in connection with employee compensation. In February 2017, the dollar value of discretionary employee bonus payments with respect to the year ended December 31, 2016 (less any retirement plan deductions and withholding taxes) was remitted through the issuance of an equivalent value of newly issued Enterprise common units under EPCO's 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) ("2008 Plan"). We issued 1,176,103 common units, which had a value of $33.7 million, in connection with the employee bonus payments. The compensation expense associated with this issuance of common units was recognized during the year ended December 31, 2016. See Note 11 for additional information regarding the 2008 Plan.

Noncontrolling Interests

Noncontrolling interests represent third party equity ownership interests in our consolidated subsidiaries (e.g., joint venture partners in entities in which we have a controlling ownership interest).

Accumulated Other Comprehensive Income (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, January 1, 2017	$ (83.8)	$ (199.8)	$ 3.6	$ (280.0)
Other comprehensive loss before reclassifications	(2.6)	(4.8)	(0.1)	(7.5)
Amounts reclassified from accumulated other comprehensive loss (income)	(49.0)	29.9	--	(19.1)
Total other comprehensive income (loss)	(51.6)	25.1	(0.1)	(26.6)
Balance, September 30, 2017	$ (135.4)	$ (174.7)	$ 3.5	$ (306.6)

	Gains (Losses) on Cash Flow Hedges: Commodity Derivative Instruments	Gains (Losses) on Cash Flow Hedges: Interest Rate Derivative Instruments	Other	Total
Balance, January 1, 2016	$ 56.6	$ (279.5)	$ 3.7	$ (219.2)
Other comprehensive loss before reclassifications	(52.2)	(16.3)	(0.1)	(68.6)
Amounts reclassified from accumulated other comprehensive loss (income)	(48.7)	27.8	--	(20.9)
Total other comprehensive income (loss)	(100.9)	11.5	(0.1)	(89.5)
Balance, September 30, 2016	$ (44.3)	$ (268.0)	$ 3.6	$ (308.7)

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

	Location	For the Three Months Ended September 30, 2017	For the Three Months Ended September 30, 2016	For the Nine Months Ended September 30, 2017	For the Nine Months Ended September 30, 2016
Losses (gains) on cash flow hedges:					
Interest rate derivatives	Interest expense	$ 10.3	$ 9.4	$ 29.9	$ 27.8
Commodity derivatives	Revenue	(10.6)	(23.0)	(49.1)	(47.6)
Commodity derivatives	Operating costs and expenses	0.5	(3.9)	0.1	(1.1)
Total		$ 0.2	$ (17.5)	$ (19.1)	$ (20.9)

For information regarding our interest rate and commodity derivative instruments, see Note 12.

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
2016			
1st Quarter	$ 0.3950	4/29/2016	5/6/2016
2nd Quarter	$ 0.4000	7/29/2016	8/5/2016
3rd Quarter	$ 0.4050	10/31/2016	11/7/2016
2017			
1st Quarter	$ 0.4150	4/28/2017	5/8/2017
2nd Quarter	$ 0.4200	7/31/2017	8/7/2017
3rd Quarter	$ 0.4225	10/31/2017	11/7/2017

In October 2017, management announced plans to recommend to the Board cash distribution increases per quarter of $0.0025 per unit with respect to each of the six fiscal quarters beginning with the third quarter of 2017 and ending with the fourth quarter of 2018. The Board declared a $0.4225 per common unit cash distribution to limited partners with respect to the third quarter of 2017, which will be paid on November 7, 2017. Management currently expects to recommend to the Board the following quarterly cash distributions through the end of 2018 (with respect to each quarter presented): $0.4250, fourth quarter of 2017; $0.4275, first quarter of 2018; $0.4300, second quarter of 2018; $0.4325, third quarter of 2018; and $0.4350, fourth quarter of 2018.

The payment of any quarterly cash distribution is subject to Board approval and management's evaluation of our financial condition, results of operations and cash flows in connection with such payment. Management will propose recommendations to the Board regarding our cash distribution growth rate for 2019 as we consider future investment opportunities and alternatives for returning capital to investors.

Note 9. Business Segments

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

Our business segments are generally organized and managed according to the types of services rendered (or technologies employed) and products produced and/or sold. Financial information regarding these segments is evaluated regularly by our chief operating decision makers in deciding how to allocate resources and in assessing operating and financial performance.

Segment Gross Operating Margin

We evaluate segment performance based on our financial measure of gross operating margin. Gross operating margin is an important performance measure of the core profitability of our operations and forms the basis of our internal financial reporting. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. 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 percent basis before any allocation of earnings to noncontrolling interests.

The following table presents our measurement of total segment gross operating margin for the periods presented. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Operating income	$ 879.2	$ 905.0	$ 2,849.5	$ 2,657.5
Adjustments to reconcile operating income to total gross operating margin:				
Add depreciation, amortization and accretion expense in operating costs and expenses	383.9	367.1	1,139.3	1,085.6
Add asset impairment and related charges in operating costs and expenses	10.0	6.8	35.2	28.7
Add net gains attributable to asset sales in operating costs and expenses	(1.1)	(8.9)	(1.1)	(2.3)
Add general and administrative costs	41.3	42.0	137.4	121.0
Adjustments for make-up rights on certain new pipeline projects:				
Add non-refundable payments received from shippers attributable to make-up rights (1)	(1.9)	1.2	19.7	10.1
Subtract the subsequent recognition of revenues attributable to make-up rights (2)	(7.0)	(5.6)	(22.9)	(25.1)
Total segment gross operating margin	$ 1,304.4	$ 1,307.6	$ 4,157.1	$ 3,875.5

(1) Since make-up rights entail a future performance obligation by the pipeline to the shipper, these receipts are recorded as deferred revenue for GAAP purposes; however, these receipts are included in gross operating margin in the period of receipt since they are nonrefundable to the shipper.
(2) As deferred revenues attributable to make-up rights are subsequently recognized as revenue under GAAP, gross operating margin must be adjusted to remove such amounts to prevent duplication since the associated non-refundable payments were previously included in gross operating margin.

Gross operating margin by segment is calculated by subtracting segment operating costs and expenses from segment revenues, with both segment totals reflecting the adjustments noted in the preceding table, as applicable, and before the elimination of intercompany transactions. The following table presents gross operating margin by segment for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Gross operating margin by segment:				
NGL Pipelines & Services	$ 770.9	$ 703.5	$ 2,386.8	$ 2,206.3
Crude Oil Pipelines & Services	190.4	254.0	691.7	633.7
Natural Gas Pipelines & Services	170.7	178.5	536.0	533.6
Petrochemical & Refined Products Services	172.4	171.6	542.6	501.9
Total segment gross operating margin	$ 1,304.4	$ 1,307.6	$ 4,157.1	$ 3,875.5

Summarized Segment Financial Information

Information by business segment, together with reconciliations to amounts presented on our Unaudited Condensed Statements of Consolidated Operations, is presented in the following table:

	Reportable Business Segments					
	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:						
Three months ended September 30, 2017	$ 2,911.1	$ 1,790.7	$ 793.3	$ 1,379.3	$ --	$ 6,874.4
Three months ended September 30, 2016	2,414.2	1,712.9	711.3	1,066.3	--	5,904.7
Nine months ended September 30, 2017	8,871.9	5,489.1	2,334.0	4,086.7	--	20,781.7
Nine months ended September 30, 2016	7,328.9	4,641.8	1,792.5	2,735.8	--	16,499.0
Revenues from related parties:						
Three months ended September 30, 2017	3.2	6.0	3.3	--	--	12.5
Three months ended September 30, 2016	2.7	10.1	2.9	--	--	15.7
Nine months ended September 30, 2017	8.8	14.4	10.0	--	--	33.2
Nine months ended September 30, 2016	7.3	29.8	7.4	--	--	44.5
Intersegment and intrasegment revenues:						
Three months ended September 30, 2017	5,055.1	2,552.9	220.1	426.4	(8,254.5)	--
Three months ended September 30, 2016	4,772.4	2,445.2	201.2	315.4	(7,734.2)	--
Nine months ended September 30, 2017	19,572.0	9,410.6	635.2	1,230.8	(30,848.6)	--
Nine months ended September 30, 2016	12,828.0	6,390.3	472.8	865.8	(20,556.9)	--
Total revenues:						
Three months ended September 30, 2017	7,969.4	4,349.6	1,016.7	1,805.7	(8,254.5)	6,886.9
Three months ended September 30, 2016	7,189.3	4,168.2	915.4	1,381.7	(7,734.2)	5,920.4
Nine months ended September 30, 2017	28,452.7	14,914.1	2,979.2	5,317.5	(30,848.6)	20,814.9
Nine months ended September 30, 2016	20,164.2	11,061.9	2,272.7	3,601.6	(20,556.9)	16,543.5
Equity in income (loss) of unconsolidated affiliates:						
Three months ended September 30, 2017	18.8	95.9	0.9	(2.2)	--	113.4
Three months ended September 30, 2016	15.9	78.4	1.0	(3.0)	--	92.3
Nine months ended September 30, 2017	53.3	266.3	2.8	(7.2)	--	315.2
Nine months ended September 30, 2016	45.0	234.3	2.9	(12.4)	--	269.8

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.

Information by business segment, together with reconciliations to our Unaudited Condensed Consolidated Balance Sheet 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	Adjustments and Eliminations	Consolidated Total
Property, plant and equipment, net: (see Note 4)						
At September 30, 2017	$ 13,892.1	$ 4,333.4	$ 8,415.7	$ 3,396.1	$ 4,942.0	$ 34,979.3
At December 31, 2016	14,091.5	4,216.1	8,403.0	3,261.2	3,320.7	33,292.5
Investments in unconsolidated affiliates: (see Note 5)						
At September 30, 2017	742.8	1,829.8	21.2	66.4	--	2,660.2
At December 31, 2016	750.4	1,824.6	21.7	80.6	--	2,677.3
Intangible assets, net: (see Note 6)						
At September 30, 2017	327.7	2,211.0	1,028.2	172.9	--	3,739.8
At December 31, 2016	350.2	2,279.0	1,054.5	180.4	--	3,864.1
Goodwill: (see Note 6)						
At September 30, 2017	2,651.7	1,841.0	296.3	956.2	--	5,745.2
At December 31, 2016	2,651.7	1,841.0	296.3	956.2	--	5,745.2
Segment assets:						
At September 30, 2017	17,614.3	10,215.2	9,761.4	4,591.6	4,942.0	47,124.5
At December 31, 2016	17,843.8	10,160.7	9,775.5	4,478.4	3,320.7	45,579.1

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. 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).

Other Revenue and Expense Information

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 2,415.3	$ 1,959.0	$ 7,460.5	$ 5,962.9
Midstream services	499.0	457.9	1,420.2	1,373.3
Total	2,914.3	2,416.9	8,880.7	7,336.2
Crude Oil Pipelines & Services:				
Sales of crude oil	1,589.0	1,538.5	4,912.7	4,141.8
Midstream services	207.7	184.5	590.8	529.8
Total	1,796.7	1,723.0	5,503.5	4,671.6
Natural Gas Pipelines & Services:				
Sales of natural gas	568.9	483.7	1,673.5	1,104.4
Midstream services	227.7	230.5	670.5	695.5
Total	796.6	714.2	2,344.0	1,799.9
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,194.2	871.3	3,519.4	2,137.9
Midstream services	185.1	195.0	567.3	597.9
Total	1,379.3	1,066.3	4,086.7	2,735.8
Total consolidated revenues	$ 6,886.9	$ 5,920.4	$ 20,814.9	$ 16,543.5
Consolidated costs and expenses				
Operating costs and expenses:				
Cost of sales	$ 5,049.6	$ 4,088.6	$ 15,116.4	$ 11,135.6
Other operating costs and expenses (1)	637.4	612.1	1,853.4	1,787.2
Depreciation, amortization and accretion	383.9	367.1	1,139.3	1,085.6
Asset impairment and related charges	10.0	6.8	35.2	28.7
Net gains attributable to asset sales	(1.1)	(8.9)	(1.1)	(2.3)
General and administrative costs	41.3	42.0	137.4	121.0
Total consolidated costs and expenses	$ 6,121.1	$ 5,107.7	$ 18,280.6	$ 14,155.8

(1) Represents the cost of operating our plants, pipelines and other fixed assets excluding: depreciation, amortization and accretion charges; asset impairment and related charges; and net losses (or gains) attributable to asset sales.

Fluctuations in our product sales revenues and related cost of sales amounts are explained in part by changes in energy commodity prices. In general, higher energy commodity prices result in an increase in our revenues attributable to product sales; however, these higher commodity prices also increase the associated cost of sales as purchase costs rise. The same correlation would be true in the case of lower 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 September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
BASIC EARNINGS PER UNIT				
Net income attributable to limited partners	$ 610.9	$ 634.6	$ 2,025.3	$ 1,854.3
Undistributed earnings allocated and cash payments on phantom unit awards (1)	(4.0)	(3.2)	(12.0)	(9.7)
Net income available to common unitholders	$ 606.9	$ 631.4	$ 2,013.3	$ 1,844.6
Basic weighted-average number of common units outstanding	2,151.1	2,097.5	2,140.7	2,072.2
Basic earnings per unit	$ 0.28	$ 0.30	$ 0.94	$ 0.89
DILUTED EARNINGS PER UNIT				
Net income attributable to limited partners	$ 610.9	$ 634.6	$ 2,025.3	$ 1,854.3
Diluted weighted-average number of units outstanding:				
Distribution-bearing common units	2,151.1	2,097.5	2,140.7	2,072.2
Phantom units (1)	9.5	8.0	9.3	7.6
Total	2,160.6	2,105.5	2,150.0	2,079.8
Diluted earnings per unit	$ 0.28	$ 0.30	$ 0.94	$ 0.89

(1) Each phantom unit award includes a distribution equivalent right ("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 September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Equity-classified awards:				
Phantom unit awards	$ 23.1	$ 19.9	$ 69.4	$ 58.6
Restricted common unit awards	--	0.8	0.5	3.7
Profits interest awards	1.4	1.5	4.5	3.8
Liability-classified awards	0.1	0.1	0.3	0.4
Total	$ 24.6	$ 22.3	$ 74.7	$ 66.5

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

At September 30, 2017, all of the outstanding phantom unit awards were granted under the 2008 Plan. The maximum number of common units authorized for issuance under the 2008 Plan was 40,000,000 at September 30, 2017. This amount will automatically increase under the terms of the 2008 Plan by 5,000,000 common units on January 1, 2018 and will continue to automatically increase annually on each 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 2008 Plan through September 30, 2017, a total of 19,032,467 additional common units were available for issuance under this plan.

EPCO serves as the general partner of four limited partnerships that were formed in 2016 (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. ("PubCo I"), EPD PubCo Unit II L.P. ("PubCo II"), EPD PubCo Unit III L.P. ("PubCo III") and EPD PrivCo Unit I L.P. ("PrivCo I").

At September 30, 2017, a small number of restricted common unit awards remained outstanding under the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan"). The 1998 Plan is effectively closed and no new awards have been granted under this plan since 2014.

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 percent per year beginning one year after the grant date and are non-vested until the required service periods expire.

At September 30, 2017, 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 January 1, 2017	7,767,501	$ 27.20
Granted (2)	4,259,620	$ 28.84
Vested	(2,417,571)	$ 28.31
Forfeited	(209,633)	$ 27.57
Phantom unit awards at September 30, 2017	9,399,917	$ 27.65

(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 2017 was $122.9 million based on a grant date market price of our common units ranging from $26.40 to $28.87 per unit. An estimated annual forfeiture rate of 3.8 percent was applied to these awards.

The 2008 Plan provides for the issuance of 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 September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Cash payments made in connection with DERs	$ 4.0	$ 3.2	$ 11.2	$ 8.5
Total intrinsic value of phantom unit awards that vested during period	1.6	3.0	67.9	40.1

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was $117.5 million at September 30, 2017, of which our share of the cost is currently estimated to be $100.0 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 2.1 years.

Profits Interest Awards

In 2016, EPCO Holdings Inc. ("EPCO Holdings"), a privately held affiliate of EPCO, contributed a portion of the Enterprise common units it owned to each of the Employee Partnerships. In exchange for these contributions, EPCO Holdings was admitted as the Class A limited partner of each Employee Partnership. Also on the applicable 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.

The following table summarizes key elements of each Employee Partnership as of September 30, 2017:

Employee Partnership	Enterprise Common Units owned by Employee Partnership	Class A Capital Base (1)	Class A Preference Return (2)	Expected Liquidation Date	Estimated Grant Date Fair Value of Profits Interest Awards (3)	Unrecognized Compensation Cost (4)
PubCo I	2,723,052 units	$63.7 million	$0.39	Feb. 2020	$13.2 million	$8.2 million
PubCo II	2,834,198 units	$66.3 million	$0.39	Feb. 2021	$14.7 million	$10.1 million
PubCo III	105,000 units	$2.5 million	$0.39	Apr. 2020	$0.6 million	$0.2 million
PrivCo I	1,111,438 units	$26.0 million	$0.39	Feb. 2021	$5.8 million	$0.8 million

(1) Represents fair market value of the Enterprise common units contributed to each Employee Partnership at the applicable contribution date.

(2) Each quarter, the Class A limited partner in each Employee Partnership is paid a cash distribution equal to the product of (i) the number of common units owned by the Employee Partnership and (ii) the Class A Preference Return of $0.39 per unit (subject to equitable adjustment in order to reflect any equity split, equity distribution or dividend, reverse split, combination, reclassification, recapitalization or other similar event affecting such common units). To the extent that the Employee Partnership has cash remaining after making this quarterly payment to the Class A limited partner, the residual cash is distributed to the Class B limited partners on a quarterly basis.

(3) Represents the total grant date fair value of the profits interest awards regardless 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 September 30, 2017. We expect to recognize our share of the unrecognized compensation cost for PubCo I, PubCo II, PubCo III and PrivCo I over a weighted-average period of 2.4 years, 3.4 years, 2.5 years and 3.4 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
PubCo I	4.0 years	0.9% to 1.5%	6.2% to 6.8%	29% to 40%
PubCo II	5.0 years	1.1% to 1.7%	6.1% to 6.8%	27% to 40%
PubCo III	4.0 years	1.0% to 1.4%	6.1% to 6.2%	31% to 40%
PrivCo I	5.0 years	1.2% to 1.6%	6.1% to 6.7%	28% to 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.

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 percent 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 January 1, 2017	682,294	$ 28.61
Vested	(679,370)	$ 28.60
Forfeited	(1,250)	$ 31.07
Restricted common units at September 30, 2017	1,674	$ 31.74

(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 within "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 September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Cash distributions paid to restricted common unitholders	$ --	$ 0.3	$ 0.3	$ 1.4
Total intrinsic value of restricted common unit awards that vested during period	0.3	0.7	18.9	28.0

We expect to recognize our share of the unrecognized compensation cost for these awards by the end of 2017.

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 September 30, 2017:

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 1.79%	Fair value hedge

The following table summarizes our portfolio of forward starting swaps at September 30, 2017:

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Expected Settlement Date	Average Rate Locked	Accounting Treatment
Future long-term debt offering	3 forward starting swaps	$275.0	2/2019	2.57%	Cash flow hedge

As a result of market conditions in August 2017, we elected to terminate forward starting swaps that were scheduled to settle in May 2018, which resulted in cash gains totaling $30.6 million. As cash flow hedges, gains on these derivative instruments will be reflected as a component of accumulated other comprehensive income and be amortized to earnings (as a decrease in interest expense) over the life of the associated future debt obligations beginning in May 2018.

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 and basis swaps.

At September 30, 2017, 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 derivative instruments and related contracts.

- The objective of our natural gas processing hedging program is to hedge an amount of earnings associated with these activities. We achieve this objective by executing fixed-price sales for a portion of our expected equity NGL production using derivative instruments and related contracts. 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 using derivative instruments and related contracts.

- 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 derivative instruments and related contracts.

The following table summarizes our portfolio of commodity derivative instruments outstanding at September 30, 2017 (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)	3.9	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	1.0	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchase of NGLs (MMBbls)	0.1	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	0.2	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	1.0	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	4.5	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	61.8	0.2	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	95.5	2.8	Cash flow hedge
NGLs inventory management activities (MMBbls)	0.4	n/a	Fair value hedge
Refined products marketing:			
Forecasted sales of refined products (MMBbls)	0.1	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	1.5	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	1.6	0.1	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	8.0	0.1	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (4,5)	91.7	17.4	Mark-to-market
NGL risk management activities (MMBbls) (5)	15.0	n/a	Mark-to-market
Refined products risk management activities (MMBbls) (5)	0.1	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	64.5	16.3	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 2018, March 2018 and March 2020, respectively.
(3) Forecasted NGL sales volumes under Natural gas processing exclude 0.2 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.
(4) Current and long-term volumes include 41.9 Bcf and 7.7 Bcf, respectively, of physical derivative instruments that are predominantly priced at a market-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.

On January 3, 2017, the Chicago Mercantile Exchange ("CME") modified its exchange rules to characterize daily variation margin amounts as "final settlement" values. The modified rule ("CME Rule 814") impacts derivative financial instruments traded on exchanges administered by the CME, including the New York Mercantile Exchange. As a result of this rule change, we began reporting the affected derivative instruments on a net basis on our balance sheet during the first quarter of 2017. The netting process results in the elimination of derivative assets, derivative liabilities and associated restricted cash and related amounts with each other as if the underlying derivative instruments had settled on the balance sheet date. Historically through December 31, 2016, we reported such derivatives on a gross basis (i.e., not netted).

Derivative transactions cleared on exchanges other than the CME (e.g., the Intercontinental Exchange or ICE) continue to be reported on a gross basis.

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

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

	Asset Derivatives				Liability Derivatives			
	September 30, 2017		December 31, 2016		September 30, 2017		December 31, 2016	
	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	$ --	Current assets	$ 0.3	Current liabilities	$ 1.6	Current liabilities	$ 0.2
Interest rate derivatives	Other assets	0.8	Other assets	36.2	Other liabilities	--	Other liabilities	0.9
Total interest rate derivatives		0.8		36.5		1.6		1.1
Commodity derivatives	Current assets	146.3	Current assets	499.2	Current liabilities	183.5	Current liabilities	662.0
Commodity derivatives	Other assets	0.3	Other assets	--	Other liabilities	0.4	Other liabilities	--
Total commodity derivatives		146.6		499.2		183.9		662.0
Total derivatives designated as hedging instruments		$ 147.4		$ 535.7		$ 185.5		$ 663.1
Derivatives not designated as hedging instruments								
Commodity derivatives	Current assets	$ 33.9	Current assets	$ 41.9	Current liabilities	$ 40.2	Current liabilities	$ 75.6
Commodity derivatives	Other assets	3.5	Other assets	0.3	Other liabilities	6.7	Other liabilities	1.8
Total commodity derivatives		$ 37.4		$ 42.2		$ 46.9		$ 77.4

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

	Offsetting of Financial Assets and Derivative Assets						
				Gross Amounts Not Offset in the Balance Sheet			
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Financial Instruments	Cash Collateral Received	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)		(iv)		(v) = (iii) + (iv)
As of September 30, 2017:							
Interest rate derivatives	$ 0.8	$ --	$ 0.8	$ (0.4)	$ --	$ --	$ 0.4
Commodity derivatives	184.0	--	184.0	(182.9)	--	--	1.1
As of December 31, 2016:							
Interest rate derivatives	$ 36.5	$ --	$ 36.5	$ (0.2)	$ --	$ --	$ 36.3
Commodity derivatives	541.4	--	541.4	(526.8)	--	--	14.6

	Offsetting of Financial Liabilities and Derivative Liabilities						
				Gross Amounts Not Offset in the Balance Sheet			
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Financial Instruments	Cash Collateral Received	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)		(iv)		(v) = (iii) + (iv)
As of September 30, 2017:							
Interest rate derivatives	$ 1.6	$ --	$ 1.6	$ (0.4)	$ --	$ --	$ 1.2
Commodity derivatives	230.8	--	230.8	(182.9)	--	(46.6)	1.3
As of December 31, 2016:							
Interest rate derivatives	$ 1.1	$ --	$ 1.1	$ (0.2)	$ --	$ --	$ 0.9
Commodity derivatives	739.4	--	739.4	(526.8)	--	(212.4)	0.2

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 September 30,		For the Nine Months Ended September 30,	
		2017	2016	2017	2016
Interest rate derivatives	Interest expense	$ 0.3	$ (3.8)	$ (0.2)	$ 3.5
Commodity derivatives	Revenue	(37.9)	(0.4)	(0.3)	(82.4)
Total		$ (37.6)	$ (4.2)	$ (0.5)	$ (78.9)

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2017	2016	2017	2016
Interest rate derivatives	Interest expense	$ (0.3)	$ 3.8	$ 0.3	$ (3.7)
Commodity derivatives	Revenue	51.4	2.1	22.7	110.9
Total		$ 51.1	$ 5.9	$ 23.0	$ 107.2

For the nine months ended September 30, 2017, the net gain of $22.4 million recognized in income from our commodity derivatives designated as fair value hedges includes $0.3 million of net losses attributable to hedge ineffectiveness. The remaining $22.7 million of net gains recognized during the nine months ended September 30, 2017 was primarily related to prompt-to-forward month price differentials that were excluded from the assessment of hedge effectiveness. For the nine months ended September 30, 2016, the net gain of $28.5 million recognized in income from our commodity derivatives designated as fair value hedges includes $1.1 million of net gains attributable to hedge ineffectiveness. The remaining $27.4 million of net gains recognized during the nine months ended September 30, 2016 was primarily related to prompt-to-forward month price differentials that were excluded from the assessment of hedge effectiveness.

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

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income (Loss) on Derivative (Effective Portion)			
	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Interest rate derivatives	$ (0.3)	$ (6.9)	$ (4.8)	$ (16.3)
Commodity derivatives – Revenue (1)	(177.3)	23.8	1.7	(53.4)
Commodity derivatives – Operating costs and expenses (1)	(0.5)	(1.1)	(4.3)	1.2
Total	$ (178.1)	$ 15.8	$ (7.4)	$ (68.5)

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

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) to Income (Effective Portion)			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2017	2016	2017	2016
Interest rate derivatives	Interest expense	$ (10.3)	$ (9.4)	$ (29.9)	$ (27.8)
Commodity derivatives	Revenue	10.6	23.0	49.1	47.6
Commodity derivatives	Operating costs and expenses	(0.5)	3.9	(0.1)	1.1
Total		$ (0.2)	$ 17.5	$ 19.1	$ 20.9

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2017	2016	2017	2016
Commodity derivatives	Operating costs and expenses	$ --	$ (0.3)	$ (1.1)	$ (0.3)
Total		$ --	$ (0.3)	$ (1.1)	$ (0.3)

Over the next twelve months, we expect to reclassify $40.4 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 $135.3 million of net losses attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings, $134.9 million as a decrease in revenue and $0.4 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 September 30,		For the Nine Months Ended September 30,	
		2017	2016	2017	2016
Commodity derivatives	Revenue	$ (15.5)	$ 18.3	$ 18.9	$ (28.3)
Commodity derivatives	Operating costs and expenses	(4.0)	--	(0.3)	--
Total		$ (19.5)	$ 18.3	$ 18.6	$ (28.3)

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.

The values for commodity derivatives at September 30, 2017 are presented before and after the application of CME Rule 814, which deems that financial instruments cleared by the CME are settled daily in connection with variation margin payments. As a result of this new exchange rule, CME-related derivatives are considered to have no fair value at the balance sheet date for financial reporting purposes; however, the derivatives remain outstanding and subject to future commodity price fluctuations until they are settled in accordance with their contractual terms.

	September 30, 2017 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	$ --	$ 0.8	$ --	$ 0.8
Commodity derivatives:				
Value before application of CME Rule 814	10.3	370.2	1.4	381.9
Impact of CME Rule 814 change	(10.3)	(187.6)	--	(197.9)
Total commodity derivatives	--	182.6	1.4	184.0
Total financial assets	$ --	$ 183.4	$ 1.4	$ 184.8
Financial liabilities:				
Liquidity Option Agreement	$ --	$ --	$ 302.6	$ 302.6
Interest rate derivatives	--	1.6	--	1.6
Commodity derivatives:				
Value before application of CME Rule 814	38.8	608.3	1.0	648.1
Impact of CME Rule 814 change	(38.8)	(378.5)	--	(417.3)
Total commodity derivatives	--	229.8	1.0	230.8
Total financial liabilities	$ --	$ 231.4	$ 303.6	$ 535.0

	December 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	$ --	$ 36.5	$ --	$ 36.5
Commodity derivatives	84.5	455.2	1.7	541.4
Total financial assets	$ 84.5	$ 491.7	$ 1.7	$ 577.9
Financial liabilities:				
Liquidity Option Agreement	$ --	$ --	$ 269.6	$ 269.6
Interest rate derivatives	--	1.1	--	1.1
Commodity derivatives	136.8	602.3	0.3	739.4
Total financial liabilities	$ 136.8	$ 603.4	$ 269.9	$ 1,010.1

Our Level 3 financial liabilities at September 30, 2017 and December 31, 2016 primarily reflect the fair value assigned to the Liquidity Option Agreement (see Note 14) at each measurement date. The carrying value of the Liquidity Option Agreement (a long-term liability) was $302.6 million and $269.6 million at September 30, 2017 and December 31, 2016, respectively.

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

	Location	For the Nine Months Ended September 30, 2017	2016
Financial asset (liability) balance, net, January 1		$ (268.2)	$ (246.7)
Total gains (losses) included in:			
Net income (1)	Revenue	0.7	0.7
Net income	Other expense, net	(5.5)	2.2
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	--	1.5
Settlements (1)	Revenue	(1.4)	(0.1)
Transfers out of Level 3		--	0.1
Financial asset (liability) balance, net, March 31		(274.4)	(242.3)
Total gains (losses) included in:			
Net income (1)	Revenue	0.1	--
Net income	Other expense, net	(18.6)	(23.3)
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	0.1	2.0
Settlements (1)	Revenue	(0.7)	(0.1)
Transfers out of Level 3		--	--
Financial asset (liability) balance, net, June 30		(293.5)	(263.7)
Total gains (losses) included in:			
Net income (1)	Revenue	0.3	0.2
Net income	Other expense, net	(8.9)	(6.9)
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	--	(4.1)
Settlements (1)	Revenue	(0.1)	(0.2)
Transfers out of Level 3		--	--
Financial asset (liability) balance, net, September 30		$ (302.2)	$ (274.7)

(1) There were $0.2 million of unrealized gains and $1.1 million of unrealized losses included in these amounts for the three and nine months ended September 30, 2017, respectively. There were unrealized gains of $0.5 million included in these amounts for the nine months ended September 30, 2016.

The following table provides quantitative information regarding our recurring Level 3 fair value measurements for commodity derivatives at September 30, 2017:

	Fair Value Financial Assets	Fair Value Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Crude oil	$ 0.7	$ 0.4	Discounted cash flow	Forward commodity prices	$49.90-$51.65/barrel
Commodity derivatives – Ethane	0.7	0.6	Discounted cash flow	Forward commodity prices	$0.28-$0.31/gallon
Total	$ 1.4	$ 1.0			

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 September 30, 2017. 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 asset impairment charges for long-lived assets by segment during each of the periods indicated:

	For the Three Months Ended September 30, 2017	For the Three Months Ended September 30, 2016	For the Nine Months Ended September 30, 2017	For the Nine Months Ended September 30, 2016
NGL Pipelines & Services	$ 5.4	$ 3.8	$ 8.4	$ 6.2
Crude Oil Pipelines & Services	1.8	--	2.4	0.9
Natural Gas Pipelines & Services	1.9	2.0	11.8	11.7
Petrochemical & Refined Products Services	0.6	1.0	0.6	2.0
Total	$ 9.7	$ 6.8	$ 23.2	$ 20.8

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

The following table presents categories of long-lived assets that were subject to non-recurring fair value measurements during the nine months ended September 30, 2017:

		Fair Value Measurements at the End of the Reporting Period Using			
	Carrying Value at September 30, 2017	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	$ --	$ --	$ --	$ --	$ 2.1
Long-lived assets held and used	9.0	7.5	--	1.5	15.9
Long-lived assets held for sale	3.0	0.5	--	2.5	4.6
Long-lived assets disposed of by sale	--	--	--	--	0.6
Total					$ 23.2

Total asset impairment and related charges during the nine months ended September 30, 2017 were $35.2 million, which consisted of $23.2 million of impairment charges attributable to long-lived assets and $12.0 million of impairment charges attributable to the write-down of spare parts classified as current assets.

The following table presents categories of long-lived assets that were subject to non-recurring fair value measurements during the nine months ended September 30, 2016:

		Fair Value Measurements at the End of the Reporting Period Using			
	Carrying Value at September 30, 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	$ --	$ --	$ --	$ --	$ 11.3
Long-lived assets held for sale	1.5	--	1.5	--	9.5
Total					$ 20.8

Total asset impairment and related charges during the nine months ended September 30, 2016 were $29.1 million, which consisted of $20.8 million of impairment charges attributable to long-lived assets, $1.2 million of impairment charges attributable to the write-down of spare parts classified as current assets and $7.1 million of related charges for equipment destroyed by fire at our Pascagoula gas plant.

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 $23.32 billion and $21.95 billion at September 30, 2017 and December 31, 2016, respectively. The aggregate carrying value of these debt obligations was $21.48 billion and $20.85 billion at September 30, 2017 and December 31, 2016, 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 September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Revenues – related parties:				
Unconsolidated affiliates	$ 12.5	$ 15.7	$ 33.2	$ 44.5
Costs and expenses – related parties:				
EPCO and its privately held affiliates	$ 262.2	$ 242.3	$ 752.7	$ 721.0
Unconsolidated affiliates	74.1	69.2	167.2	199.5
Total	$ 336.3	$ 311.5	$ 919.9	$ 920.5

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

	September 30, 2017	December 31, 2016
Accounts receivable - related parties:		
Unconsolidated affiliates	$ 3.2	$ 1.1
Accounts payable - related parties:		
EPCO and its privately held affiliates	$ 82.7	$ 88.9
Unconsolidated affiliates	26.3	16.2
Total	$ 109.0	$ 105.1

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 September 30, 2017, 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
685,514,092	32%

Of the total number of units held by EPCO and its privately held affiliates, 48,000,000 have been pledged as security under the credit facilities of a privately held affiliate at September 30, 2017. 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 nine months ended September 30, 2017 and 2016, we paid EPCO and its privately held affiliates cash distributions totaling $835.5 million and $793.6 million, respectively. 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 September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Operating costs and expenses	$ 230.1	$ 212.9	$ 657.6	$ 628.9
General and administrative expenses	27.6	25.9	81.5	79.5
Total costs and expenses	$ 257.7	$ 238.8	$ 739.1	$ 708.4

Note 14. Commitments and Contingencies

Litigation

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

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

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

At September 30, 2017 and December 31, 2016, our accruals for litigation contingencies were $4.8 million and $0.3 million, respectively, and were recorded in our Unaudited Condensed Consolidated Balance Sheets as a component of “Other current liabilities.” Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves uncertainties. In the event the assumptions we use to evaluate these matters change in future periods or new information becomes available, we may be required to record additional accruals. In an effort to mitigate expenses associated with litigation, we may settle legal proceedings out of court.

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

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

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 was then submitted to the Court of Appeals for its consideration. On July 18, 2017, a panel of the Court of Appeals issued a unanimous opinion reversing the trial court's judgment as to all of ETP's claims against Enterprise, rendering judgment that ETP take nothing on those claims, and affirming Enterprise's counterclaim against ETP of approximately $0.8 million, plus interest. We are grateful to the Dallas Court of Appeals for their hard work in this case and their reaffirmation of the importance of written contracts in business transactions.

On August 31, 2017, ETP filed a motion for rehearing before the Dallas Court of Appeals, which was denied on September 13, 2017. ETP has stated that they intend to appeal the unanimous opinion of the Dallas Court of Appeals, and file a petition for review with the Texas Supreme Court. As of September 30, 2017, we have not recorded a provision for this matter as management continues to believe that payment of damages by us in this case is not probable. We continue to monitor developments involving this matter.

PDH Litigation. In July 2013, we executed a contract with Foster Wheeler USA Corporation ("Foster Wheeler") pursuant to which Foster Wheeler was to serve as the general contractor responsible for the engineering, procurement, construction and installation of our propane dehydrogenation ("PDH") facility. In November 2014, Foster Wheeler was acquired by an affiliate of AMEC plc to form Amec Foster Wheeler plc, and Foster Wheeler is now known as Amec Foster Wheeler USA Corporation ("AFW"). In December 2015, Enterprise and AFW entered into a transition services agreement under which AFW was partially terminated from the PDH project. In December 2015, Enterprise engaged a second contractor, Optimized Process Designs LLC, to complete the construction and installation of the PDH facility.

On September 2, 2016, we terminated AFW for cause and filed a lawsuit in the 151st Judicial Civil District Court of Harris County, Texas against AFW and its parent company, Amec Foster Wheeler plc, asserting claims for breach of contract, breach of warranty, fraudulent inducement, string-along fraud, gross negligence, professional negligence, negligent misrepresentation and attorneys' fees. We intend to diligently prosecute these claims and seek all direct, consequential, and exemplary damages to which we may be entitled.

Contractual Obligations

Scheduled Maturities of Debt. 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 $26.0 million and $27.0 million during the three months ended September 30, 2017 and 2016, respectively. For the nine months ended September 30, 2017 and 2016, consolidated lease and rental expense was $78.1 million and $81.8 million, respectively. Our operating lease commitments at September 30, 2017 did not differ materially from those reported in our 2016 Form 10-K.

Purchase Obligations. Our consolidated purchase obligations at September 30, 2017 did not differ materially from those reported in our 2016 Form 10-K.

Liquidity Option Agreement

We entered into a put option agreement (the "Liquidity Option Agreement" or "Liquidity Option") with Oiltanking Holding Americas, Inc. ("OTA") and Marquard & Bahls AG ("M&B") in connection with the first step of the Oiltanking acquisition ("Step 1"). Under the Liquidity Option Agreement, we granted M&B the option to sell to us 100 percent of the issued and outstanding capital stock of OTA at any time within a 90-day period commencing on February 1, 2020. 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 deferred tax liabilities. To the extent that the sum of OTA's deferred tax liabilities exceeds the then current book value of the Liquidity Option liability, we would recognize expense for the difference.

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 $302.6 million and $269.6 million at September 30, 2017 and December 31, 2016, respectively. The fair value of the Liquidity Option, at any measurement date, represents the present value of estimated federal and state income tax payments that we believe a market participant would incur on the future taxable income of OTA. We expect that OTA's taxable income would, in turn, be based on an allocation of our partnership's taxable income to the common units held by OTA and reflect any tax planning we believe could be employed. Our valuation estimate for the Liquidity Option at September 30, 2017 is based on several inputs that are not observable in the market (i.e., Level 3 inputs) such as the following:

- OTA remains in existence (i.e., is not dissolved and its assets sold) between one and 30 years following exercise of the Liquidity Option, depending on the liquidity preference of its owner. An equal probability that OTA would be dissolved was assigned to each year in the 30-year forecast period;
- OTA assumes approximately $2.2 billion of associated long-term debt (30-year maturity) immediately after the Liquidity Option is exercised. For purposes of the valuation at September 30, 2017, we used a market rate commensurate with this level of debt and tenure of approximately 4.35%. If the assumption of debt is excluded from the valuation model at September 30, 2017 (and all other inputs remained the same), the estimated fair value of the Liquidity Option would have increased by $226.6 million and resulted in the recognition of an equal amount of expense at the time of change;
- Forecasted annual growth rates of Enterprise's taxable earnings before interest, taxes, depreciation and amortization ranging from 0.1% to 13.6%;
- OTA's ownership interest in Enterprise common units is assumed to be diluted over time in connection with Enterprise's issuance of equity for general company reasons. For purposes of the valuation at September 30, 2017, we used ownership interests ranging from 1.8% to 2.5%;
- OTA pays an aggregate federal and state income tax rate of 38% on its taxable income; and
- A discount rate of 7.5% based on our weighted-average cost of capital at September 30, 2017.

Furthermore, our valuation estimate incorporates probability-weighted scenarios reflecting the likelihood that M&B may elect to divest a portion of the Enterprise common units held by OTA prior to exercise of the option. At September 30, 2017, based on these scenarios, we expect that OTA would own approximately 88 percent of the 54,807,352 Enterprise common units it received in Step 1 when the option period begins in February 2020. If our valuation estimate had assumed that OTA owned all of the Enterprise common units it received in Step 1 at the time of exercise (and all other inputs remained the same), the estimated fair value of the Liquidity Option liability at September 30, 2017 would have increased by $41.4 million.

Changes in the fair value of the Liquidity Option are recognized in earnings as a component of other income (expense) on our Unaudited Condensed Statements of Consolidated Operations. Results for the three months ended September 30, 2017 and 2016 include $8.9 million and $6.9 million, respectively, of aggregate non-cash expense attributable to accretion and changes in management estimates regarding inputs to the valuation model. Results for the nine months ended September 30, 2017 and 2016 include $33.0 million and $28.0 million, respectively, of such expense.

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 Nine Months Ended September 30,	
	2017	2016
Decrease (increase) in:		
Accounts receivable – trade	$ (137.3)	$ (370.4)
Accounts receivable – related parties	(2.2)	(0.2)
Inventories	(92.7)	(701.6)
Prepaid and other current assets	284.3	(71.8)
Other assets	(89.3)	(1.3)
Increase (decrease) in:		
Accounts payable – trade	3.5	(36.8)
Accounts payable – related parties	37.7	13.6
Accrued product payables	98.7	615.1
Accrued interest	(134.3)	(149.5)
Other current liabilities	(481.5)	201.1
Other liabilities	1.0	12.1
Net effect of changes in operating accounts	$ (512.1)	$ (489.7)

We incurred liabilities for construction in progress that had not been paid at September 30, 2017 and December 31, 2016 of $399.0 million and $124.3 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Unaudited Condensed Statements of Consolidated Cash Flows.

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

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
September 30, 2017

	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	$ 92.9	$ 41.6	$ (34.8)	$ 99.7	$ --	$ --	$ 99.7
Accounts receivable – trade, net	1,484.6	1,907.6	--	3,392.2	--	--	3,392.2
Accounts receivable – related parties	143.4	806.1	(945.5)	4.0	--	(0.8)	3.2
Inventories	1,716.4	267.2	(0.4)	1,983.2	--	--	1,983.2
Derivative assets	157.9	22.3	--	180.2	--	--	180.2
Prepaid and other current assets	195.9	194.5	(18.0)	372.4	0.2	--	372.6
Total current assets	3,791.1	3,239.3	(998.7)	6,031.7	0.2	(0.8)	6,031.1
Property, plant and equipment, net	5,426.5	29,551.3	1.5	34,979.3	--	--	34,979.3
Investments in unconsolidated affiliates	40,529.2	4,251.6	(42,120.6)	2,660.2	22,633.3	(22,633.3)	2,660.2
Intangible assets, net	687.8	3,065.9	(13.9)	3,739.8	--	--	3,739.8
Goodwill	459.5	5,285.7	--	5,745.2	--	--	5,745.2
Other assets	254.0	103.6	(213.2)	144.4	0.6	--	145.0
Total assets	$ 51,148.1	$ 45,497.4	$ (43,344.9)	$ 53,300.6	$ 22,634.1	$ (22,634.1)	$ 53,300.6
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 3,008.6	$ 0.4	$ --	$ 3,009.0	$ --	$ --	$ 3,009.0
Accounts payable – trade	243.3	511.8	(34.8)	720.3	--	--	720.3
Accounts payable – related parties	910.6	159.5	(961.1)	109.0	0.9	(0.9)	109.0
Accrued product payables	2,134.4	1,626.8	(1.0)	3,760.2	--	--	3,760.2
Accrued interest	206.4	0.1	--	206.5	--	--	206.5
Derivative liabilities	192.9	32.4	--	225.3	--	--	225.3
Other current liabilities	66.1	355.9	(15.0)	407.0	--	1.4	408.4
Total current liabilities	6,762.3	2,686.9	(1,011.9)	8,437.3	0.9	0.5	8,438.7
Long-term debt	21,696.1	14.8	--	21,710.9	--	--	21,710.9
Deferred tax liabilities	4.9	45.6	(0.6)	49.9	--	3.8	53.7
Other long-term liabilities	57.9	403.5	(215.6)	245.8	302.6	--	548.4
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	22,626.9	42,270.9	(42,289.8)	22,608.0	22,330.6	(22,608.0)	22,330.6
Noncontrolling interests	--	75.7	173.0	248.7	--	(30.4)	218.3
Total equity	22,626.9	42,346.6	(42,116.8)	22,856.7	22,330.6	(22,638.4)	22,548.9
Total liabilities and equity	$ 51,148.1	$ 45,497.4	$ (43,344.9)	$ 53,300.6	$ 22,634.1	$ (22,634.1)	$ 53,300.6

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
December 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	$ 366.2	$ 58.9	$ (7.5)	$ 417.6	$ --	$ --	$ 417.6
Accounts receivable – trade, net	1,499.4	1,830.3	(0.2)	3,329.5	--	--	3,329.5
Accounts receivable – related parties	131.5	961.4	(1,090.7)	2.2	--	(1.1)	1.1
Inventories	1,357.5	413.5	(0.5)	1,770.5	--	--	1,770.5
Derivative assets	464.8	76.6	--	541.4	--	--	541.4
Prepaid and other current assets	290.7	191.1	(13.7)	468.1	--	--	468.1
Total current assets	4,110.1	3,531.8	(1,112.6)	6,529.3	--	(1.1)	6,528.2
Property, plant and equipment, net	4,796.5	28,495.7	0.3	33,292.5	--	--	33,292.5
Investments in unconsolidated affiliates	39,995.5	4,227.9	(41,546.1)	2,677.3	22,317.1	(22,317.1)	2,677.3
Intangible assets, net	700.2	3,178.2	(14.3)	3,864.1	--	--	3,864.1
Goodwill	459.5	5,285.7	--	5,745.2	--	--	5,745.2
Other assets	222.6	41.0	(177.5)	86.1	0.6	--	86.7
Total assets	$ 50,284.4	$ 44,760.3	$ (42,850.2)	$ 52,194.5	$ 22,317.7	$ (22,318.2)	$ 52,194.0
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 2,576.7	$ 0.1	$ --	$ 2,576.8	$ --	$ --	$ 2,576.8
Accounts payable – trade	133.1	272.1	(7.5)	397.7	--	--	397.7
Accounts payable – related parties	1,071.5	139.6	(1,106.0)	105.1	1.1	(1.1)	105.1
Accrued product payables	1,944.5	1,670.3	(1.1)	3,613.7	--	--	3,613.7
Accrued interest	340.7	0.1	--	340.8	--	--	340.8
Derivative liabilities	590.3	147.4	--	737.7	--	--	737.7
Other current liabilities	173.5	316.5	(12.0)	478.0	--	0.7	478.7
Total current liabilities	6,830.3	2,546.1	(1,126.6)	8,249.8	1.1	(0.4)	8,250.5
Long-term debt	21,105.7	15.2	--	21,120.9	--	--	21,120.9
Deferred tax liabilities	5.0	45.1	(1.1)	49.0	--	3.7	52.7
Other long-term liabilities	13.5	400.6	(179.8)	234.3	269.6	--	503.9
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	22,329.9	41,675.3	(41,713.4)	22,291.8	22,047.0	(22,291.8)	22,047.0
Noncontrolling interests	--	78.0	170.7	248.7	--	(29.7)	219.0
Total equity	22,329.9	41,753.3	(41,542.7)	22,540.5	22,047.0	(22,321.5)	22,266.0
Total liabilities and equity	$ 50,284.4	$ 44,760.3	$ (42,850.2)	$ 52,194.5	$ 22,317.7	$ (22,318.2)	$ 52,194.0

**Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Three Months Ended September 30, 2017**

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 8,199.3	$ 4,354.2	$ (5,666.6)	$ 6,886.9	$ --	$ --	$ 6,886.9
Costs and expenses:							
Operating costs and expenses	8,019.6	3,727.0	(5,666.8)	6,079.8	--	--	6,079.8
General and administrative costs	8.0	32.9	0.1	41.0	0.3	--	41.3
Total costs and expenses	8,027.6	3,759.9	(5,666.7)	6,120.8	0.3	--	6,121.1
Equity in income of unconsolidated affiliates	692.5	141.4	(720.5)	113.4	620.1	(620.1)	113.4
Operating income	864.2	735.7	(720.4)	879.5	619.8	(620.1)	879.2
Other income (expense):							
Interest expense	(244.1)	(2.4)	2.6	(243.9)	--	--	(243.9)
Other, net	2.3	0.6	(2.6)	0.3	(8.9)	--	(8.6)
Total other expense, net	(241.8)	(1.8)	--	(243.6)	(8.9)	--	(252.5)
Income before income taxes	622.4	733.9	(720.4)	635.9	610.9	(620.1)	626.7
Provision for income taxes	(3.2)	(1.8)	--	(5.0)	--	(0.4)	(5.4)
Net income	619.2	732.1	(720.4)	630.9	610.9	(620.5)	621.3
Net income attributable to noncontrolling interests	--	(1.5)	(10.1)	(11.6)	--	1.2	(10.4)
Net income attributable to entity	$ 619.2	$ 730.6	$ (730.5)	$ 619.3	$ 610.9	$ (619.3)	$ 610.9

**Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Three Months Ended September 30, 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	$ 7,291.8	$ 3,932.4	$ (5,303.8)	$ 5,920.4	$ --	$ --	$ 5,920.4
Costs and expenses:							
Operating costs and expenses	7,099.6	3,270.3	(5,304.2)	5,065.7	--	--	5,065.7
General and administrative costs	6.3	35.0	0.2	41.5	0.5	--	42.0
Total costs and expenses	7,105.9	3,305.3	(5,304.0)	5,107.2	0.5	--	5,107.7
Equity in income of unconsolidated affiliates	701.6	129.3	(738.6)	92.3	642.0	(642.0)	92.3
Operating income	887.5	756.4	(738.4)	905.5	641.5	(642.0)	905.0
Other income (expense):							
Interest expense	(248.8)	(4.2)	2.1	(250.9)	--	--	(250.9)
Other, net	2.1	0.7	(2.1)	0.7	(6.9)	--	(6.2)
Total other expense, net	(246.7)	(3.5)	--	(250.2)	(6.9)	--	(257.1)
Income before income taxes	640.8	752.9	(738.4)	655.3	634.6	(642.0)	647.9
Provision for income taxes	(2.7)	(1.6)	--	(4.3)	--	(0.5)	(4.8)
Net income	638.1	751.3	(738.4)	651.0	634.6	(642.5)	643.1
Net income attributable to noncontrolling interests	--	(1.7)	(8.1)	(9.8)	--	1.3	(8.5)
Net income attributable to entity	$ 638.1	$ 749.6	$ (746.5)	$ 641.2	$ 634.6	$ (641.2)	$ 634.6

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Nine Months Ended September 30, 2017

	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	$ 29,273.1	$ 12,936.8	$ (21,395.0)	$ 20,814.9	$ --	$ --	$ 20,814.9
Costs and expenses:							
Operating costs and expenses	28,590.7	10,947.9	(21,395.4)	18,143.2	--	--	18,143.2
General and administrative costs	23.5	112.5	(0.1)	135.9	1.5	--	137.4
Total costs and expenses	28,614.2	11,060.4	(21,395.5)	18,279.1	1.5	--	18,280.6
Equity in income of unconsolidated affiliates	2,137.4	417.1	(2,239.3)	315.2	2,059.8	(2,059.8)	315.2
Operating income	2,796.3	2,293.5	(2,238.8)	2,851.0	2,058.3	(2,059.8)	2,849.5
Other income (expense):							
Interest expense	(736.7)	(9.4)	7.1	(739.0)	--	--	(739.0)
Other, net	6.8	1.2	(7.1)	0.9	(33.0)	--	(32.1)
Total other expense, net	(729.9)	(8.2)	--	(738.1)	(33.0)	--	(771.1)
Income before income taxes	2,066.4	2,285.3	(2,238.8)	2,112.9	2,025.3	(2,059.8)	2,078.4
Provision for income taxes	(9.4)	(9.4)	--	(18.8)	--	(1.3)	(20.1)
Net income	2,057.0	2,275.9	(2,238.8)	2,094.1	2,025.3	(2,061.1)	2,058.3
Net income attributable to noncontrolling interests	--	(4.8)	(32.0)	(36.8)	--	3.8	(33.0)
Net income attributable to entity	$ 2,057.0	$ 2,271.1	$ (2,270.8)	$ 2,057.3	$ 2,025.3	$ (2,057.3)	$ 2,025.3

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Nine Months Ended September 30, 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	$ 19,847.9	$ 11,009.3	$ (14,313.7)	$ 16,543.5	$ --	$ --	$ 16,543.5
Costs and expenses:							
Operating costs and expenses	19,192.8	9,156.3	(14,314.3)	14,034.8	--	--	14,034.8
General and administrative costs	16.4	102.3	0.2	118.9	2.1	--	121.0
Total costs and expenses	19,209.2	9,258.6	(14,314.1)	14,153.7	2.1	--	14,155.8
Equity in income of unconsolidated affiliates	1,971.6	389.3	(2,091.1)	269.8	1,884.4	(1,884.4)	269.8
Operating income	2,610.3	2,140.0	(2,090.7)	2,659.6	1,882.3	(1,884.4)	2,657.5
Other income (expense):							
Interest expense	(726.4)	(14.8)	5.6	(735.6)	--	--	(735.6)
Other, net	6.0	2.1	(5.6)	2.5	(28.0)	--	(25.5)
Total other expense, net	(720.4)	(12.7)	--	(733.1)	(28.0)	--	(761.1)
Income before income taxes	1,889.9	2,127.3	(2,090.7)	1,926.5	1,854.3	(1,884.4)	1,896.4
Provision for income taxes	(5.5)	(6.2)	--	(11.7)	--	(1.4)	(13.1)
Net income	1,884.4	2,121.1	(2,090.7)	1,914.8	1,854.3	(1,885.8)	1,883.3
Net income attributable to noncontrolling interests	--	(5.3)	(27.6)	(32.9)	--	3.9	(29.0)
Net income attributable to entity	$ 1,884.4	$ 2,115.8	$ (2,118.3)	$ 1,881.9	$ 1,854.3	$ (1,881.9)	$ 1,854.3

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Three Months Ended September 30, 2017

	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	$ 480.2	$ 693.3	$ (720.4)	$ 453.1	$ 433.0	$ (442.7)	$ 443.4
Comprehensive income attributable to noncontrolling interests	--	(1.5)	(10.1)	(11.6)	--	1.2	(10.4)
Comprehensive income attributable to entity	$ 480.2	$ 691.8	$ (730.5)	$ 441.5	$ 433.0	$ (441.5)	$ 433.0

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Three Months Ended September 30, 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	$ 649.9	$ 738.0	$ (738.6)	$ 649.3	$ 632.9	$ (640.8)	$ 641.4
Comprehensive income attributable to noncontrolling interests	--	(1.7)	(8.1)	(9.8)	--	1.3	(8.5)
Comprehensive income attributable to entity	$ 649.9	$ 736.3	$ (746.7)	$ 639.5	$ 632.9	$ (639.5)	$ 632.9

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Nine Months Ended September 30, 2017

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 2,011.6	$ 2,294.8	$ (2,238.8)	$ 2,067.6	$ 1,998.7	$ (2,034.6)	$ 2,031.7
Comprehensive income attributable to noncontrolling interests	--	(4.8)	(32.0)	(36.8)	--	3.8	(33.0)
Comprehensive income attributable to entity	$ 2,011.6	$ 2,290.0	$ (2,270.8)	$ 2,030.8	$ 1,998.7	$ (2,030.8)	$ 1,998.7

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Nine Months Ended September 30, 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	$ 1,824.5	$ 2,091.6	$ (2,090.8)	$ 1,825.3	$ 1,764.8	$ (1,796.3)	$ 1,793.8
Comprehensive income attributable to noncontrolling interests	--	(5.3)	(27.6)	(32.9)	--	3.9	(29.0)
Comprehensive income attributable to entity	$ 1,824.5	$ 2,086.3	$ (2,118.4)	$ 1,792.4	$ 1,764.8	$ (1,792.4)	$ 1,764.8

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
For the Nine Months Ended September 30, 2017

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	**Other Subsidiaries (Non-guarantor)**	**EPO and Subsidiaries Eliminations and Adjustments**	**Consolidated EPO and Subsidiaries**	**Enterprise Products Partners L.P. (Guarantor)**	**Eliminations and Adjustments**	**Consolidated Total**
Operating activities:							
Net income	$ 2,057.0	$ 2,275.9	$ (2,238.8)	$ 2,094.1	$ 2,025.3	$ (2,061.1)	$ 2,058.3
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	158.9	1,062.8	(0.3)	1,221.4	--	--	1,221.4
Equity in income of unconsolidated affiliates	(2,137.4)	(417.1)	2,239.3	(315.2)	(2,059.8)	2,059.8	(315.2)
Distributions received on earnings from unconsolidated affiliates	802.6	202.2	(688.6)	316.2	2,664.2	(2,664.2)	316.2
Net effect of changes in operating accounts and other operating activities	1,662.3	(2,157.4)	(27.5)	(522.6)	61.2	0.6	(460.8)
Net cash flows provided by operating activities	2,543.4	966.4	(715.9)	2,793.9	2,690.9	(2,664.9)	2,819.9
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(625.8)	(1,492.4)	--	(2,118.2)	--	--	(2,118.2)
Cash used for business combination, net of cash received	(7.3)	(191.4)	--	(198.7)	--	--	(198.7)
Proceeds from asset sales	1.6	4.6	--	6.2	--	--	6.2
Other investing activities	(1,160.9)	(32.1)	1,487.5	294.5	(867.5)	867.5	294.5
Cash used in investing activities	(1,792.4)	(1,711.3)	1,487.5	(2,016.2)	(867.5)	867.5	(2,016.2)
Financing activities:							
Borrowings under debt agreements	53,184.4	--	(34.0)	53,150.4	--	--	53,150.4
Repayments of debt	(52,133.1)	(0.1)	--	(52,133.2)	--	--	(52,133.2)
Cash distributions paid to owners	(2,664.2)	(734.0)	734.0	(2,664.2)	(2,660.4)	2,664.2	(2,660.4)
Cash payments made in connection with DERs	--	--	--	--	(11.2)	--	(11.2)
Cash distributions paid to noncontrolling interests	--	(7.2)	(28.9)	(36.1)	--	0.7	(35.4)
Cash contributions from noncontrolling interests	--	0.1	0.3	0.4	--	--	0.4
Net cash proceeds from issuance of common units	--	--	--	--	877.2	--	877.2
Cash contributions from owners	867.5	1,470.2	(1,470.2)	867.5	--	(867.5)	--
Other financing activities	7.3	--	--	7.3	(29.0)	--	(21.7)
Cash provided by (used in) financing activities	(738.1)	729.0	(798.8)	(807.9)	(1,823.4)	1,797.4	(833.9)
Net change in cash and cash equivalents	12.9	(15.9)	(27.2)	(30.2)	--	--	(30.2)
Cash and cash equivalents, January 1	13.4	57.2	(7.5)	63.1	--	--	63.1
Cash and cash equivalents, September 30	$ 26.3	$ 41.3	$ (34.7)	$ 32.9	$ --	$ --	$ 32.9

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
For the Nine Months Ended September 30, 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	$ 1,884.4	$ 2,121.1	$ (2,090.7)	$ 1,914.8	$ 1,854.3	$ (1,885.8)	$ 1,883.3
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	131.9	1,023.7	(0.3)	1,155.3	--	--	1,155.3
Equity in income of unconsolidated affiliates	(1,971.6)	(389.3)	2,091.1	(269.8)	(1,884.4)	1,884.4	(269.8)
Distributions received on earnings from unconsolidated affiliates	733.1	196.9	(648.4)	281.6	2,477.3	(2,477.3)	281.6
Net effect of changes in operating accounts and other operating activities	1,281.6	(1,742.7)	46.1	(415.0)	22.9	0.7	(391.4)
Net cash flows provided by operating activities	2,059.4	1,209.7	(602.2)	2,666.9	2,470.1	(2,478.0)	2,659.0
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(989.6)	(1,420.2)	--	(2,409.8)	--	--	(2,409.8)
Cash used for business combination, net of cash received	--	(1,000.0)	--	(1,000.0)	--	--	(1,000.0)
Proceeds from asset sales	27.9	16.0	--	43.9	--	--	43.9
Other investing activities	(2,177.0)	(84.2)	1,931.4	(329.8)	(2,161.2)	2,161.2	(329.8)
Cash used in investing activities	(3,138.7)	(2,488.4)	1,931.4	(3,695.7)	(2,161.2)	2,161.2	(3,695.7)
Financing activities:							
Borrowings under debt agreements	50,183.8	41.4	(41.4)	50,183.8	--	--	50,183.8
Repayments of debt	(48,776.4)	(0.1)	--	(48,776.5)	--	--	(48,776.5)
Cash distributions paid to owners	(2,477.3)	(677.5)	677.5	(2,477.3)	(2,448.3)	2,477.3	(2,448.3)
Cash payments made in connection with DERs	--	--	--	--	(8.5)	--	(8.5)
Cash distributions paid to noncontrolling interests	--	(7.3)	(29.1)	(36.4)	--	0.7	(35.7)
Cash contributions from noncontrolling interests	--	20.1	--	20.1	--	--	20.1
Net cash proceeds from issuance of common units	--	--	--	--	2,170.4	--	2,170.4
Cash contributions from owners	2,161.2	1,890.0	(1,890.0)	2,161.2	--	(2,161.2)	--
Other financing activities	(8.0)	--	--	(8.0)	(22.5)	--	(30.5)
Cash provided by financing activities	1,083.3	1,266.6	(1,283.0)	1,066.9	(308.9)	316.8	1,074.8
Net change in cash and cash equivalents	4.0	(12.1)	46.2	38.1	--	--	38.1
Cash and cash equivalents, January 1	--	69.6	(50.6)	19.0	--	--	19.0
Cash and cash equivalents, September 30	$ 4.0	$ 57.5	$ (4.4)	$ 57.1	$ --	$ --	$ 57.1

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

For the Three and Nine Months Ended September 30, 2017 and 2016

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, 2016 (the "2016 Form 10-K"), as filed on February 24, 2017 with the U.S. Securities and Exchange Commission ("SEC"). 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 32 percent of our limited partner interests at September 30, 2017.

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 third quarter of 2017 compared to the third quarter of 2016. Likewise, the phrase "period-to-period" means the nine months ended September 30, 2017 compared to the nine months ended September 30, 2016.

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 Part I, Item 1A of our 2016 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 date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Overview of Business

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

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the U.S., Canada and 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 export and import terminals (including those used to export liquefied petroleum gases, or "LPG," and ethane); crude oil gathering, transportation, storage, and export and import terminals; petrochemical and refined products transportation, storage, export and import 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 50,000 miles of pipelines; 260 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 percent 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.

Our operations are reported under four business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services and (iv) Petrochemical & Refined Products Services. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for information regarding our business segments.

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

Affiliates of EPCO to purchase $100 Million of Enterprise Common Units in November 2017

Affiliates of EPCO have indicated to our management that they plan to purchase $100 million of the partnership's common units through its distribution reinvestment plan ("DRIP") in connection with the distribution to be paid with respect to the third quarter of 2017 on November 7, 2017.

Enterprise Management Provides Guidance with regards to Distribution Growth through 2018

In October 2017, management announced plans to recommend to the Board cash distribution increases per quarter of $0.0025 per unit with respect to each of the six fiscal quarters beginning with the third quarter of 2017 and ending with the fourth quarter of 2018. The Board declared a $0.4225 per common unit cash distribution to limited partners with respect to the third quarter of 2017, which will be paid on November 7, 2017. Management currently expects to recommend to the Board the following quarterly cash distributions through the end of 2018 (with respect to each quarter presented): $0.4250, fourth quarter of 2017; $0.4275, first quarter of 2018; $0.4300, second quarter of 2018; $0.4325, third quarter of 2018; and $0.4350, fourth quarter of 2018.

The recommended distribution growth rate should further strengthen our distribution coverage, increase our retained distributable cash flow available to fund growth capital opportunities, and reduce unitholder dilution by decreasing the amount of equity we may need to issue. Management believes that moderation in the growth rate of our near-term cash distributions should enhance our ability to be self-funding for the equity portion of capital expenditures by 2019.

The payment of any quarterly cash distribution is subject to Board approval and management's evaluation of our financial condition, results of operations and cash flows in connection with such payment. Management will propose recommendations to the Board regarding our cash distribution growth rate for 2019 as we consider future investment opportunities and alternatives for returning capital to investors.

Enterprise Enters into New Revolving Credit Facilities

In September 2017, we announced that EPO had entered into new revolving credit facilities that effectively extended the respective maturity dates of its then existing revolving credit facilities. The new facilities consist of a $4.0 billion Multi-Year Revolving Credit Facility that matures in September 2022 and a $1.5 billion 364-Day Revolving Credit Agreement that matures in September 2018. The new facilities replaced EPO's then existing revolving credit facilities, and EPO's aggregate borrowing capacity remains unchanged. As of the filing date of this quarterly report, there were no borrowings outstanding under the new revolving credit facilities.

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.

Enterprise Prices $1.7 Billion Principal Amount of Junior Subordinated Notes

In August 2017, we announced that EPO had priced a public offering of two series of junior subordinated notes comprised of $700 million aggregate principal amount of Junior Subordinated Notes D due August 2077 (the "Junior Notes D") and $1.0 billion aggregate principal amount of Junior Subordinated Notes E also due August 2077 (the "Junior Notes E"). Net proceeds from the issuance of Junior Notes D and E were used for (i) the temporary repayment of approximately $900 million of amounts then outstanding under EPO's commercial paper program and (ii) the repayment of $800 million in principal amount of Senior Notes L that matured in September 2017.

Successful Appeal in connection with ETP Matter

In July 2017, a panel of the Dallas Court of Appeals issued a unanimous opinion in which we prevailed in our appeal against Energy Transfer Partners, L.P. ("ETP"). This appeal stemmed from an adverse 2014 jury verdict in Dallas, Texas in a lawsuit filed by ETP over a proposed pipeline project that was cancelled due to a lack of customer support.

In April 2011, Enterprise and ETP signed a series of agreements disclaiming any partnership or joint venture absent executed definitive documents and board approvals of the two companies. Definitive agreements were never executed and board approval was never obtained. The parties signed these disclaiming agreements precisely to avoid the type of lawsuit brought by ETP. We are grateful to the Dallas Court of Appeals for their hard work in this case and their reaffirmation of the importance of written contracts in business transactions.

On August 31, 2017, ETP filed a motion for rehearing before the Dallas Court of Appeals, which was denied on September 13, 2017. ETP has stated that they intend to appeal the unanimous opinion of the Dallas Court of Appeals, and file a petition for review with the Texas Supreme Court. As of September 30, 2017, we have not recorded a provision for this matter as management continues to believe that payment of damages by us in this case is not probable. We continue to monitor developments involving this matter.

For additional information regarding the appeal, see Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Announcement Regarding Potential Ethylene Export Marine Terminal
In July 2017, we announced the execution of a letter of intent with Navigator Holdings Ltd. ("Navigator") to develop an ethylene export marine terminal at our Morgan's Point complex on the Houston Ship Channel. Key definitive documents are nearing completion, and formation of the 50/50 joint venture remains subject to final approval and execution of those agreements by us and Navigator, as well as approval by our respective boards of directors. Construction of the terminal is predicated on receiving sufficient long-term customer commitments.

We would manage the construction, operations and commercial activities of the proposed terminal. Our Morgan's Point complex, which includes our ethane export marine terminal, features a 45-foot draft that can accommodate a variety of vessel and barge types. If constructed, the ethylene export terminal would be connected to our high-capacity ethylene salt dome storage and related pipeline system, both of which are under construction (see "*Plans to Develop Ethylene Storage and Transportation Projects*").

Plans to Expand Orla Natural Gas Processing Facility in West Texas
In June 2017, we announced plans to add a second processing train ("Orla II") to our cryogenic natural gas processing facility currently under construction near Orla, Texas in Reeves County. Orla II is expected to add 300 MMcf/d of incremental processing capacity to the facility and double the inlet capacity of the facility to 600 MMcf/d and increase extraction of NGLs from up to 40 MBPD to up to 80 MBPD.

Mixed NGLs extracted at the Orla facility will be delivered into our fully integrated NGL system, including the recently announced Shin Oak NGL Pipeline. Residue natural gas volumes from the facility will be transported to the Waha area through our Texas Intrastate system. The Orla facility is designed to support the continued growth in NGL-rich natural gas production from the Delaware Basin of West Texas and southeastern New Mexico and is supported by long-term customer commitments.

Upon completion, the Orla facility will bring the partnership's total Permian Basin natural gas processing capacity to more than 1 Bcf/d with more than 150 MBPD of NGL extraction capacity. The Orla II capacity is expected to be placed into service during the third quarter of 2018.

Plans to Build Shin Oak NGL Pipeline from Permian Basin to Mont Belvieu, Texas
In April 2017, we announced plans to build a 24-inch diameter pipeline (the "Shin Oak NGL Pipeline") to transport growing NGL production from the Permian Basin to our NGL fractionation and storage complex located in Mont Belvieu, Texas. The Shin Oak NGL Pipeline is expected to have an initial design capacity of 250 MBPD and be expandable to 600 MBPD. The project is supported by long-term shipper commitments and is expected to be placed into service during the second quarter of 2019.

Plans to Develop Ethylene Storage and Transportation Projects
In April 2017, we announced two expansion projects that will further develop our ethylene infrastructure in the Houston, Texas area. First, we plan to repurpose a large, high-capacity ethane storage well at our Mont Belvieu, Texas complex into ethylene storage. Following completion of this project, which is expected as early as the third quarter of 2018, the 5.3 MMBbl cavern will be able to inject/withdraw ethylene at a rate of 210,000 pounds per hour (or approximately 2,000 barrels per hour), expandable to 420,000 pounds per hour (or approximately 4,000 barrels per hour). There are seven third party ethylene pipelines within two miles of the ethylene well, providing significant connectivity opportunities for the high-capacity system.

Further supporting our ethylene capabilities, we also plan to build a 24-mile, 12-inch or larger diameter ethylene pipeline extending from Mont Belvieu to Bayport, Texas. The new pipeline would have the potential to connect both producing and consuming customers located south of the Houston Ship Channel to our facility in Mont Belvieu. The ethylene pipeline will be routed through our Morgan's Point complex, which provides us with future flexibility should we develop an ethylene export marine terminal at the facility.

Completion of Azure Acquisition
In April 2017, we closed on the acquisition of a midstream energy business from Azure Midstream Partners, LP and its operating subsidiaries (collectively, "Azure") for $191.4 million in cash. The acquired business assets, which are located primarily in East Texas, include over 730 miles of natural gas gathering pipelines and two natural gas processing facilities with an aggregate processing capacity of 130 MMcf/d. The acquired business serves production from the Haynesville Shale and Bossier, Cotton Valley and Travis Peak formations.

For additional information regarding the Azure acquisition, see Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Plans to Build Ninth NGL Fractionator at Our Mont Belvieu, Texas Complex
In March 2017, we resumed construction of our ninth NGL fractionator at our Mont Belvieu, Texas complex in anticipation of increased NGL production from the Permian Basin. The new fractionator, which is expected to be completed by mid-2018, would have a nameplate capacity of 85 MBPD. We have secured the necessary permits and emission credits for this project. Upon completion of this expansion project, we would have approximately 755 MBPD of total NGL fractionation capacity at our Mont Belvieu complex and a combined 1.2 MMBPD of capacity across all of our NGL fractionators.

Plans to Construct Isobutane Dehydrogenation Unit at Mont Belvieu
In January 2017, we announced plans to construct a new isobutane dehydrogenation ("iBDH") unit at our Mont Belvieu complex that is expected to have the capability to produce 425,000 tons per year of isobutylene. The project, which is underwritten by long-term contracts with investment-grade customers, is expected to be completed in the fourth quarter of 2019. Isobutylene produced by the new plant will provide additional feedstocks for our downstream octane enhancement and petrochemical facilities.

Historically, steam crackers and refineries have been the major source of propane and butane olefins for downstream use. However, with the increased use of light-end feedstocks, specifically ethane, the need for on-purpose olefins production has increased. Like our PDH facility, the iBDH plant will help meet market demand where traditional supplies have been reduced. The new iBDH plant will increase our production of high purity and low purity isobutylene, which are used as feedstock to manufacture lubricants, rubber products and alkylate for gasoline blendstock, as well as methyl tertiary butyl ether for export.

Results of Operations

Summarized Consolidated Income Statement Data

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Revenues	$ 6,886.9	$ 5,920.4	$ 20,814.9	$ 16,543.5
Costs and expenses:				
Operating costs and expenses:				
Cost of sales	5,049.6	4,088.6	15,116.4	11,135.6
Other operating costs and expenses	637.4	612.1	1,853.4	1,787.2
Depreciation, amortization and accretion expenses	383.9	367.1	1,139.3	1,085.6
Net gains attributable to asset sales	(1.1)	(8.9)	(1.1)	(2.3)
Asset impairment and related charges	10.0	6.8	35.2	28.7
Total operating costs and expenses	6,079.8	5,065.7	18,143.2	14,034.8
General and administrative costs	41.3	42.0	137.4	121.0
Total costs and expenses	6,121.1	5,107.7	18,280.6	14,155.8
Equity in income of unconsolidated affiliates	113.4	92.3	315.2	269.8
Operating income	879.2	905.0	2,849.5	2,657.5
Interest expense	(243.9)	(250.9)	(739.0)	(735.6)
Change in fair market value of Liquidity Option Agreement	(8.9)	(6.9)	(33.0)	(28.0)
Other, net	0.3	0.7	0.9	2.5
Provision for income taxes	(5.4)	(4.8)	(20.1)	(13.1)
Net income	621.3	643.1	2,058.3	1,883.3
Net income attributable to noncontrolling interests	(10.4)	(8.5)	(33.0)	(29.0)
Net income attributable to limited partners	$ 610.9	$ 634.6	$ 2,025.3	$ 1,854.3

Consolidated Revenues

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 2,415.3	$ 1,959.0	$ 7,460.5	$ 5,962.9
Midstream services	499.0	457.9	1,420.2	1,373.3
Total	2,914.3	2,416.9	8,880.7	7,336.2
Crude Oil Pipelines & Services:				
Sales of crude oil	1,589.0	1,538.5	4,912.7	4,141.8
Midstream services	207.7	184.5	590.8	529.8
Total	1,796.7	1,723.0	5,503.5	4,671.6
Natural Gas Pipelines & Services:				
Sales of natural gas	568.9	483.7	1,673.5	1,104.4
Midstream services	227.7	230.5	670.5	695.5
Total	796.6	714.2	2,344.0	1,799.9
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,194.2	871.3	3,519.4	2,137.9
Midstream services	185.1	195.0	567.3	597.9
Total	1,379.3	1,066.3	4,086.7	2,735.8
Total consolidated revenues	$ 6,886.9	$ 5,920.4	$ 20,814.9	$ 16,543.5

Selected Energy Commodity Price Data

The following table presents selected 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)
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
2nd Quarter	$1.95	$0.20	$0.49	$0.62	$0.63	$0.96	$0.33	$0.19	$45.59	$47.35
3rd Quarter	$2.81	$0.19	$0.47	$0.63	$0.67	$0.98	$0.38	$0.24	$44.94	$46.52
4th Quarter	$2.98	$0.24	$0.58	$0.83	$0.90	$1.08	$0.36	$0.24	$49.29	$50.53
2016 Averages	$2.46	$0.20	$0.48	$0.65	$0.68	$0.94	$0.34	$0.21	$43.32	$44.88
2017 by quarter:										
1st Quarter	$3.32	$0.23	$0.71	$0.98	$0.94	$1.10	$0.47	$0.32	$51.91	$53.52
2nd Quarter	$3.19	$0.25	$0.63	$0.76	$0.75	$1.07	$0.41	$0.28	$48.28	$50.31
3rd Quarter	$2.99	$0.26	$0.77	$0.91	$0.92	$1.10	$0.42	$0.28	$48.20	$51.62
2017 Averages	$3.17	$0.25	$0.70	$0.88	$0.87	$1.09	$0.43	$0.29	$49.46	$51.82

(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 IHS Chemical, a division of IHS Inc. ("IHS Chemical"). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by IHS Chemical.
(4) Crude oil prices are based on commercial index prices for West Texas Intermediate ("WTI") as measured on the New York Mercantile Exchange ("NYMEX") and for Light Louisiana Sweet ("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. The weighted-average indicative market price for NGLs was $0.68 per gallon in the third quarter of 2017 versus $0.49 per gallon during the third quarter of 2016. Likewise, the weighted-average indicative market price for NGLs was $0.65 per gallon during the nine months ended September 30, 2017 compared to $0.46 per gallon during the same period in 2016.

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

We attempt to mitigate commodity price exposure through our hedging activities and the use of 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.

<u>Revenues</u>
Third Quarter of 2017 Compared to Third Quarter of 2016. Total revenues for the third quarter of 2017 increased $966.5 million when compared to the third quarter of 2016. Revenues from the marketing of NGLs and crude oil increased a net $506.8 million quarter-to-quarter primarily due to higher sales prices, which accounted for a $964.5 million increase, partially offset by a $457.7 million decrease due to lower sales volumes. Revenues from the marketing of natural gas, petrochemicals, refined products and octane additives increased $408.1 million quarter-to-quarter primarily due to higher sales prices, which accounted for a $236.1 million increase, and higher sales volumes, which accounted for an additional $172.0 million increase.

Revenues from midstream services increased a net $51.6 million when compared to the third quarter of 2016 primarily due to the ongoing expansion of our operations. Revenues increased $20.5 million quarter-to-quarter primarily due to higher deficiency fees on our South Texas crude pipelines. Revenues increased $16.7 million quarter-to-quarter from our Ethane Export Terminal that was placed into service in September 2016. The remaining $14.4 million quarter-to-quarter increase in revenues from midstream services is primarily due to an increase in volumes on our Appalachia-to-Texas Express (or "ATEX") pipeline and our Pascagoula gas plant being operational during the third quarter of 2017.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016. Total revenues for the nine months ended September 30, 2017 increased $4.27 billion when compared to the nine months ended September 30, 2016. Revenues from the marketing of NGLs and crude oil increased a net $2.27 billion period-to-period primarily due to higher sales prices, which accounted for a $3.31 billion increase, partially offset by a $1.04 billion decrease due to lower sales volumes. Revenues from the marketing of natural gas, petrochemicals, refined products and octane additives increased $1.95 billion period-to-period primarily due to higher sales prices, which accounted for a $1.15 billion increase, and higher sales volumes, which accounted for an additional $805.6 million increase.

Revenues from midstream services increased a net $52.3 million when compared to the nine months ended September 30, 2016 primarily due to the ongoing expansion of our operations. Revenues increased $37.7 million period-to-period from our Ethane Export Terminal that was placed into service in September 2016. Revenues increased $37.2 million period-to-period primarily due to higher deficiency fees on our South Texas crude pipelines. The remaining $22.6 million quarter-to-quarter decrease in revenues from midstream services is primarily due to lower firm capacity reservation revenues on the Haynesville Extension pipeline and lower volumes and lower average gathering fees on our Jonah Gathering System.

<u>Operating costs and expenses</u>
Third Quarter of 2017 Compared to Third Quarter of 2016. Total operating costs and expenses for the third quarter of 2017 increased $1.01 billion when compared to the third quarter of 2016. The cost of sales associated with our marketing of NGLs and crude oil increased a net $542.3 million quarter-to-quarter primarily due to higher purchase prices, which accounted for a $933.0 million increase, partially offset by a $390.7 million decrease due to lower sales volumes. The cost of sales associated with our marketing of natural gas, petrochemicals, refined products and octane additives increased $418.7 million quarter-to-quarter primarily due to higher purchase prices, which accounted for a $244.5 million increase, and higher sales volumes, which accounted for an additional $174.2 million increase.

Other operating costs and expenses for the third quarter of 2017 increased a net $25.3 million when compared to the third quarter of 2016. Other operating costs and expenses increased primarily due to higher employee compensation costs.

Depreciation, amortization and accretion expense in operating costs and expenses for the third quarter of 2017 increased $16.8 million when compared to the third quarter of 2016 primarily due to assets we constructed and placed into service since the third quarter of 2016.

Operating costs and expenses also include $10.0 million and $6.8 million of non-cash asset impairment and related charges for the third quarters of 2017 and 2016, respectively. Our non-cash asset impairment charges for the third quarter of 2017 primarily relate to the write-down of assets held for sale and natural gas pipeline laterals in Texas. Our asset impairment charges for the third quarter of 2016 primarily relate to the planned abandonment of pipeline and storage assets in Texas.

We recorded net gains within operating costs and expenses of $1.1 million and $8.9 million attributable to asset sales for the third quarters of 2017 and 2016, respectively.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016. Total operating costs and expenses for the nine months ended September 30, 2017 increased $4.11 billion when compared to the nine months ended September 30, 2016. The cost of sales associated with our marketing of NGLs and crude oil increased a net $2.20 billion period-to-period primarily due to higher purchase prices, which accounted for a $3.08 billion increase, partially offset by an $883.4 million decrease due to lower sales volumes. The cost of sales associated with our marketing of natural gas, petrochemicals, refined products and octane additives increased $1.78 billion period-to-period primarily due to higher purchase prices, which accounted for a $1.08 billion increase, and higher sales volumes, which accounted for an additional $700.9 million increase.

Other operating costs and expenses for the nine months ended September 30, 2017 increased a net $66.2 million when compared to the nine months ended September 30, 2016. Other operating costs and expenses increased primarily due to higher employee compensation and power-related costs, partially offset by $17.4 million of proceeds received in connection with a legal settlement involving our Acadian Gas System in the second quarter of 2017.

Depreciation, amortization and accretion expense in operating costs and expenses for the nine months ended September 30, 2017 increased $53.7 million when compared to the nine months ended September 30, 2016 primarily due to assets we constructed and placed into service since the third quarter of 2016.

Operating costs and expenses also include $35.2 million and $28.7 million of non-cash asset impairment and related charges for the nine months ended September 30, 2017 and 2016, respectively. Our non-cash asset impairment charges for the nine months ended September 30, 2017 primarily relate to the write-down of materials held as spare parts and natural gas pipeline laterals in Texas. Asset impairment charges for the nine months ended September 30, 2016 primarily relate to the planned abandonment of pipeline and storage assets in Texas and a loss on the Pascagoula gas plant due to a fire in June 2016.

General and administrative costs

General and administrative costs for the third quarter of 2017 decreased $0.7 million when compared to the third quarter of 2016. General and administrative costs for the nine months ended September 30, 2017 increased $16.4 million when compared to the nine months ended September 30, 2016 primarily due to higher legal, regulatory and employee compensation costs.

Equity in income of unconsolidated affiliates

Equity income from our unconsolidated affiliates for the three and nine months ended September 30, 2017 increased $21.1 million and $45.4 million, respectively, when compared to the same periods in 2016 primarily due to an increase in earnings from our investments in crude oil pipelines.

Operating income

Operating income for the three and nine months ended September 30, 2017 decreased $25.8 million and increased $192.0 million, respectively, due to the previously described quarter-to-quarter and period-to-period changes in revenues, operating costs and expenses, general and administrative costs and equity in income of unconsolidated affiliates.

Interest expense
Interest expense for the third quarter of 2017 decreased $7.0 million when compared to the third quarter of 2016. Interest expense for the nine months ended September 30, 2017 increased $3.4 million when compared to the nine months ended September 30, 2016. The following table presents the components of our consolidated interest expense for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
Interest charged on debt principal outstanding	$ 281.0	$ 273.8	$ 826.7	$ 815.8
Impact of interest rate hedging program, including related amortization	10.1	8.1	28.1	22.2
Interest costs capitalized in connection with construction projects (1)	(53.6)	(38.9)	(137.7)	(127.8)
Other (2)	6.4	7.9	21.9	25.4
Total	$ 243.9	$ 250.9	$ 739.0	$ 735.6

(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) on a straight line basis 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 $7.2 million quarter-to-quarter primarily due to increased debt principal amounts outstanding during the third quarter of 2017, which accounted for a $4.4 million increase, and the effect of higher overall interest rates during the third quarter of 2017, which accounted for a $2.8 million increase. Our weighted-average debt principal balance for the third quarter of 2017 was $24.2 billion compared to $23.69 billion for the third quarter of 2016. 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” and “Capital Spending” within this Part I, Item 2.

For the nine months ended September 30, 2017, interest charged on debt principal outstanding increased a net $10.9 million period-to-period primarily due to increased debt principal amounts outstanding during the nine months ended September 30, 2017, which accounted for a $21.2 million increase, partially offset by the effect of lower overall interest rates during the nine months ended September 30, 2017, which accounted for a $10.3 million decrease. Our weighted-average debt principal balance for the nine months ended September 30, 2017 was $23.87 billion compared to $23.23 billion for the nine months ended September 30, 2016.

Change in fair value of Liquidity Option Agreement
The change in fair value of the Liquidity Option Agreement reflects non-cash expense attributable to accretion and changes in management estimates regarding inputs to the valuation model. For the three months ended September 30, 2017, our expense resulting from changes in fair value of the Liquidity Option Agreement increased $2.0 million when compared to the same period in 2016. For the nine months ended September 30, 2017, this expense increased $5.0 million when compared to the same period in 2016. For information regarding the Liquidity Option Agreement, see Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Income taxes
Income taxes primarily reflect our state tax obligations under the Revised Texas Franchise Tax. Our provision for income taxes for the three and nine months ended September 30, 2017 increased $0.6 million and $7.0 million, respectively, when compared to the same periods in 2016.

Total Gross Operating Margin

We evaluate segment performance based on our financial measure of gross operating margin. Gross operating margin is an important performance measure of the core profitability of our operations and forms the basis of our internal financial reporting. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results.

The following table presents gross operating margin by segment and non-GAAP total gross operating margin for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
Gross operating margin by segment:				
NGL Pipelines & Services	$ 770.9	$ 703.5	$ 2,386.8	$ 2,206.3
Crude Oil Pipelines & Services	190.4	254.0	691.7	633.7
Natural Gas Pipelines & Services	170.7	178.5	536.0	533.6
Petrochemical & Refined Products Services	172.4	171.6	542.6	501.9
Total segment gross operating margin (1)	1,304.4	1,307.6	4,157.1	3,875.5
Net adjustment for shipper make-up rights	8.9	4.4	3.2	15.0
Total gross operating margin	$ 1,313.3	$ 1,312.0	$ 4,160.3	$ 3,890.5

(1) Within the context of this table, total segment gross operating margin represents a subtotal and corresponds to measures similarly titled within our business segment disclosures found in Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Total gross operating margin includes equity in the earnings of unconsolidated affiliates, but is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Total gross operating margin is presented on a 100 percent basis before any allocation of earnings to noncontrolling interests.

Gross operating margin by segment for NGL Pipelines & Services and Crude Oil Pipelines & Services reflect adjustments for shipper make-up rights that are included in management's evaluation of segment results. However, these adjustments are excluded from non-GAAP total gross operating margin.

The GAAP financial measure most directly comparable to total gross operating margin is operating income. For a discussion of operating income and its components, see the previous section titled "Consolidated Income Statement Highlights" within this Item 2. The following table presents a reconciliation of operating income to total gross operating margin for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
Operating income (GAAP)	$ 879.2	$ 905.0	$ 2,849.5	$ 2,657.5
Adjustments to reconcile operating income to total gross operating margin:				
Add depreciation, amortization and accretion expense	383.9	367.1	1,139.3	1,085.6
Add asset impairment and related charges in operating costs and expenses	10.0	6.8	35.2	28.7
Add net losses or subtract net gains attributable to asset sales	(1.1)	(8.9)	(1.1)	(2.3)
Add general and administrative costs	41.3	42.0	137.4	121.0
Total gross operating margin (non-GAAP)	$ 1,313.3	$ 1,312.0	$ 4,160.3	$ 3,890.5

Each of our business segments benefits from the supporting role of our marketing activities. The main purpose of our marketing activities is to support the utilization and expansion of assets across our midstream energy asset network by increasing the volumes handled by such assets, which results in additional fee-based earnings for each business segment. In performing these support roles, our marketing activities also seek to participate in supply and demand opportunities as a supplemental source of gross operating margin for the partnership. The financial results of our marketing efforts fluctuate due to changes in volumes handled and overall market conditions, which are influenced by current and forward market prices for the products bought and sold.

The following information highlights significant changes in our quarter-to-quarter and period-to-period segment results (i.e., our gross operating margin by segment amounts) and the primary drivers of such changes. The volume statistics presented 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.

Estimated Impact of Hurricane Harvey on Results for the Third Quarter of 2017

In late August and early September 2017, the Gulf Coast region of Texas, including its critical energy infrastructure, was impacted by the cumulative effects of Hurricane Harvey. Impacts on the energy industry included, but were not limited to, severe flooding and limited access to facilities, disruptions to energy demand from area refineries and petrochemical facilities and the closure of all ports on the Texas Gulf Coast, which limited access to export markets. Although operating at reduced rates, many of our plant, pipeline and storage assets along the Texas Gulf Coast remained operational during the storm.

We estimate that Hurricane Harvey reduced our gross operating margin for the third quarter of 2017 by approximately $35 million. Of this amount, approximately $30 million represents the combined net impact of lower than anticipated volumes and lost business opportunities. The remaining $5 million represents expenses we incurred during the quarter in connection with hurricane-related repair and recovery costs.

The following table summarizes the estimated reduction in our total gross operating margin by business segment due to the effects of Hurricane Harvey in the third quarter of 2017 (dollars in millions):

Impact on total gross operating margin by segment:		
Petrochemical & Refined Products Services	$	(25.4)
NGL Pipelines & Services		(7.1)
Crude Oil Pipelines & Services		(1.8)
Natural Gas Pipelines & Services		(0.3)
Total Estimated Impact due to the effects of Hurricane Harvey	$	(34.6)

As a result of our deductible levels, we do not expect any reimbursement from insurance in connection with property damage or business interruption claims from Hurricane Harvey.

Business Segment Highlights

The following discussions of gross operating margin by segment are based on amounts actually recognized in our Unaudited Condensed Statements of Consolidated Operations for the third quarters of 2017 and 2016 and the respective year-to-date periods. Our actual gross operating margin amounts for the third quarter of 2017 include the approximately $5 million of hurricane-related repair and recovery costs discussed in the previous section.

Where we believe that the effects of Hurricane Harvey had a material impact on the performance of a business for the third quarter of 2017 (i.e., reduced throughput volumes), we have noted the approximate impact, which is based on management’s best estimate for this recent event.

NGL Pipelines & Services

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Segment gross operating margin:				
Natural gas processing and related NGL marketing activities	$ 203.2	$ 203.3	$ 685.8	$ 618.5
NGL pipelines, storage and terminals	435.4	377.9	1,326.6	1,212.8
NGL fractionation	132.3	122.3	374.4	375.0
Total	$ 770.9	$ 703.5	$ 2,386.8	$ 2,206.3
Selected volumetric data:				
Equity NGL production (MBPD) (1)	166	116	160	136
Fee-based natural gas processing (MMcf/d) (2)	4,753	4,578	4,650	4,857
NGL pipeline transportation volumes (MBPD)	3,052	2,854	3,131	2,933
NGL marine terminal volumes (MBPD)	456	373	499	439
NGL fractionation volumes (MBPD)	815	791	818	822

(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

Third Quarter of 2017 Compared to Third Quarter of 2016. Gross operating margin from natural gas processing and related NGL marketing activities for the third quarter of 2017 decreased a net $0.1 million when compared to the third quarter of 2016.

Gross operating margin from our natural gas processing plants in Louisiana and Mississippi increased a combined $16.5 million quarter-to-quarter primarily due to our Pascagoula gas plant being operational during the third quarter of 2017. The Pascagoula facility was shut down in late June 2016 in connection with an equipment fire, which resulted in significant damage to its processing equipment. Repairs to the Pascagoula facility were completed in December 2016 and it was returned to commercial service at that time. Gross operating margin for the third quarter of 2016 includes $7.1 million of costs related to fire response activities at Pascagoula. Overall, fee-based natural gas processing volumes and equity NGL production from our Louisiana and Mississippi gas plants increased 487 MMcf/d and 5 MBPD, respectively, quarter-to-quarter.

Gross operating margin from our South Eddy natural gas processing plant increased $1.1 million quarter-to-quarter primarily due to higher fee-based processing volumes. Fee-based natural gas processing volumes and equity NGL production for this plant increased 130 MMcf/d and 6 MBPD, respectively, quarter-to-quarter. The South Eddy plant commenced operations in May 2016 and was continuing to ramp up its production during the third quarter of 2016.

Gross operating margin from our NGL marketing activities decreased a net $9.5 million quarter-to-quarter primarily due to lower sales volumes, which accounted for a $37.8 million decrease, partially offset by higher average sales margins, which accounted for a $25.9 million increase. Results from NGL marketing's activities in support of our storage assets decreased $21.1 million quarter-to-quarter, while marketing strategies in support of our transportation assets increased $10.9 million quarter-to-quarter.

Gross operating margin from our Meeker, Pioneer and Chaco natural gas processing plants decreased a combined $4.4 million quarter-to-quarter primarily due to higher maintenance and other operating costs, which accounted for a $6.4 million decrease, partially offset by higher processing volumes, which accounted for a $3.4 million increase. Equity NGL production from these plants increased 27 MBPD quarter-to-quarter.

Gross operating margin from our natural gas processing plants in South Texas decreased $2.8 million quarter-to-quarter primarily due to lower average processing margins, which decreased $2.1 million including an unfavorable quarter-to-quarter impact from hedging results of $9.1 million. Lower producer drilling activity in South Texas contributed to a 403 MMcf/d decrease in fee-based natural gas processing volumes for these plants; however, equity NGL production increased 12 MBPD quarter-to-quarter.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016. Gross operating margin from natural gas processing and related NGL marketing activities for the nine months ended September 30, 2017 increased a net $67.3 million when compared to the nine months ended September 30, 2016.

Gross operating margin from our NGL marketing activities increased a net $33.0 million period-to-period primarily due to higher sales volumes, which accounted for a $37.5 million increase, and lower operating costs, which accounted for an additional $6.6 million increase, partially offset by the effects of lower average sales margins, which accounted for an $11.1 million decrease. Results from NGL marketing's activities in support of our storage assets increased $16.2 million period-to-period, with NGL marketing's activities in support of our plant assets accounting for an additional $8.7 million period-to-period increase. On a combined basis, gross operating margin from NGL marketing's other strategies increased $8.1 million period-to-period.

Gross operating margin from our Louisiana and Mississippi gas processing plants increased a combined $26.4 million period-to-period primarily due to the Pascagoula plant being in operation for all of 2017. As noted earlier, the Pascagoula plant was shut down in late June 2016 due to a fire. As a result, gross operating margin from the Pascagoula facility increased $20.4 million period-to-period, which includes $7.1 million of costs incurred during the third quarter of 2016 in connection with fire response activities. Fee-based natural gas processing volumes for our Louisiana and Mississippi plants increased a combined 135 MMcf/d period-to-period.

Gross operating margin from our Meeker, Pioneer and Chaco natural gas processing plants increased a combined $15.4 million period-to-period primarily due to higher average processing margins, which accounted for a $22.3 million increase, partially offset by higher operating costs, which accounted for a $6.4 million decrease. On a combined basis for these three plants, fee-based natural gas processing volumes and equity NGL production decreased 62 MMcf/d and increased 16 MBPD, respectively, period-to-period.

Gross operating margin from our South Eddy natural gas processing plant increased a net $1.8 million period-to-period. Fee-based natural gas processing volumes and equity NGL production for this plant increased 120 MMcf/d and 5 MBPD, respectively, period-to-period. As previously noted, the South Eddy plant commenced operations in May 2016.

Gross operating margin from our natural gas processing plants in South Texas decreased a net $5.0 million period-to-period primarily due to lower fee-based processing volumes, which accounted for a net $12.8 million decrease, and lower average processing fees, which accounted for an additional $3.2 million decrease, partially offset by higher average processing margins, which accounted for an $11.6 million increase. Lower producer drilling activity in South Texas contributed to a 406 MMcf/d decrease in fee-based natural gas processing volumes for these plants.

NGL pipelines, storage and terminals

Third Quarter of 2017 Compared to Third Quarter of 2016. Gross operating margin from NGL pipelines, storage and terminal assets for the third quarter of 2017 increased a net $57.5 million when compared to the third quarter of 2016.

Gross operating margin from our Morgan's Point Ethane Export Terminal, which was placed into commercial operations in September 2016, and Houston Ship Channel Pipeline System increased a combined $17.2 million quarter-to-quarter primarily due to higher volumes. Ethane loading volumes at Morgan's Point were 100 MBPD during the third quarter of 2017 compared to 20 MBPD during the third quarter of 2016. Transportation volumes on our Houston Ship Channel Pipeline System increased 87 MBPD quarter-to-quarter primarily due to shipments of ethane from our Mont Belvieu complex to the Morgan's Point Ethane Export Terminal.

Gross operating margin from our ATEX pipeline increased $15.4 million quarter-to-quarter primarily due to higher transportation volumes, which increased 26 MBPD quarter-to-quarter.

Gross operating margin from our storage complex in Mont Belvieu for NGLs and related products increased $10.2 million quarter-to-quarter primarily due to higher average fees.

Gross operating margin from our Tri-States NGL Pipeline increased $6.2 million quarter-to-quarter primarily due to a 22 MBPD (net to our interest) increase in transportation volumes. Transportation volumes for the third quarter of 2016 were negatively impacted by the June 2016 fire at our Pascagoula natural gas processing plant, which reduced mixed NGLs transported on the Tri-States NGL Pipeline to regional fractionators. As noted earlier, the Pascagoula plant returned to commercial service in December 2016.

Gross operating margin from our Seminole, Chaparral and affiliated pipelines increased a combined $7.9 million quarter-to-quarter primarily due to higher transportation volumes. On a combined basis, NGL transportation volumes on these pipelines increased 44 MBPD primarily due to increased production from natural gas processing plants located in the Rocky Mountains and Permian Basin, including our South Eddy facility.

Gross operating margin from our equity investments in the Texas Express Gathering System and the Texas Express Pipeline increased a combined $5.9 million quarter-to-quarter primarily due to contractual increases in committed shipper volumes. On a combined basis, NGL transportation volumes for these pipeline systems increased 3 MBPD quarter-to-quarter (net to our interest).

Gross operating margin from our Dixie Pipeline and related terminals increased a net $0.4 million quarter-to-quarter primarily due to higher transportation volumes, which increased 31 MBPD quarter-to-quarter and accounted for a $3.5 million increase, partially offset by higher maintenance and other operating costs, which accounted for a $2.4 million decrease.

Gross operating margin from our South Texas NGL Pipeline System decreased $4.9 million quarter-to-quarter primarily due to lower average transportation volumes, which accounted for a $3.3 million decrease, and lower average transportation fees, which accounted for an additional $0.7 million decrease. Transportation volumes on the South Texas NGL Pipeline System decreased 17 MBPD quarter-to-quarter.

Based on our analysis of the effects of Hurricane Harvey, we believe that actual third quarter of 2017 results from our NGL pipelines, storage and terminals were approximately $5.1 million lower than we expected primarily due to lower than anticipated volumes.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016. Gross operating margin from NGL pipelines, storage and terminal assets for the nine months ended September 30, 2017 increased a net $113.8 million when compared to the nine months ended September 30, 2016.

Gross operating margin from our storage complex in Mont Belvieu for NGLs and related products increased $39.0 million period-to-period primarily due to higher average fees in 2017.

Gross operating margin from ATEX increased $35.4 million period-to-period primarily due to contractual increases in committed shipper volumes. Transportation volumes for ATEX increased 14 MBPD period-to-period.

Gross operating margin from our Morgan’s Point Ethane Export Terminal and Houston Ship Channel Pipeline System increased a combined $28.3 million period-to-period primarily due to higher volumes. Ethane loading volumes at our Morgan’s Point Ethane Export Terminal increased 55 MBPD period-to-period. As noted previously, this terminal commenced operations in September 2016. In addition, transportation volumes on our Houston Ship Channel Pipeline System increased 96 MBPD period-to-period primarily due to shipments of ethane from Mont Belvieu to the Morgan’s Point terminal.

Gross operating margin from our equity investments in the Texas Express Gathering System and the Texas Express Pipeline increased a combined $12.2 million period-to-period primarily due to contractual increases in committed shipper volumes. On a combined basis, NGL transportation volumes for these pipeline systems increased 5 MBPD period-to-period (net to our interest).

Gross operating margin from our Tri-States NGL Pipeline increased $8.1 million period-to-period primarily due to an 11 MBPD (net to our interest) increase in transportation volumes.

Gross operating margin from our Seminole, Chaparral and affiliated pipelines increased a combined $9.8 million period-to-period primarily due to higher transportation volumes. On a combined basis, NGL transportation volumes on these pipelines increased 55 MBPD primarily due to increased production from natural gas processing plants located in the Permian Basin and Rocky Mountains.

Gross operating margin from our Dixie Pipeline and related terminals increased a net $5.8 million period-to-period primarily due to higher transportation volumes, which increased 22 MBPD period-to-period and accounted for a $7.7 million increase, partially offset by higher maintenance and other operating costs, which accounted for a $2.7 million decrease.

Gross operating margin from our South Texas NGL Pipeline System decreased a net $15.2 million period-to-period primarily due to lower transportation fees, which accounted for a $10.1 million decrease, higher maintenance costs, which accounted for a $3.9 million decrease, and lower transportation volumes, which accounted for an additional $2.4 million of the decrease. Transportation volumes for the South Texas NGL Pipeline System decreased 18 MBPD period-to-period.

NGL fractionation

Third Quarter of 2017 Compared to Third Quarter of 2016. Gross operating margin from NGL fractionation for the third quarter of 2017 increased a net $10.0 million when compared to the third quarter of 2016.

Gross operating margin from our Hobbs NGL fractionator increased $4.1 million quarter-to-quarter primarily due to higher fractionation volumes of 13 MBPD, which accounted for a $2.4 million increase, and higher product blending revenues, which accounted for a $2.2 million increase. Gross operating margin from our Norco NGL fractionator increased $2.2 million quarter-to-quarter primarily due to higher product blending revenues.

Gross operating margin from our Mont Belvieu NGL fractionators increased a net $1.7 million quarter-to-quarter primarily due to higher average fractionation fees and blending revenues, which accounted for a $10.4 million increase, and higher fractionation volumes, which accounted for an additional $5.5 million increase, partially offset by higher storage and other operating expenses of $14.5 million. Net to our interest, NGL fractionation volumes for our Mont Belvieu plants increased 19 MBPD.

Gross operating margin from our Shoup and Armstrong facilities decreased a combined $0.9 million quarter-to-quarter primarily due to an aggregate 18 MBPD decrease in volumes attributable to lower producer drilling activity in South Texas.

Based on our analysis of the effects of Hurricane Harvey, we believe that actual third quarter of 2017 results from NGL fractionation were approximately $6.5 million lower than we expected primarily due to lower than anticipated volumes.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016. Gross operating margin from NGL fractionation for the nine months ended September 30, 2017 decreased a net $0.6 million when compared to the nine months ended September 30, 2016. Gross operating margin from our Shoup and Armstrong facilities decreased $3.9 million period-to-period primarily due to a 23 MBPD decrease in fractionation volumes attributable to lower producer drilling activity in South Texas. Gross operating margin from the remainder of our NGL fractionation facilities increased a net $3.3 million period-to-period primarily due to higher volumes.

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 September 30,		For the Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
Segment gross operating margin	$ 190.4	$ 254.0	$ 691.7	$ 633.7
Selected volumetric data:				
Crude oil pipeline transportation volumes (MBPD)	1,458	1,397	1,430	1,383
Crude oil marine terminal volumes (MBPD)	452	520	472	504

Third Quarter of 2017 Compared to Third Quarter of 2016. Gross operating margin from our Crude Oil Pipelines & Services segment for the third quarter of 2017 decreased a net $63.6 million when compared to the third quarter of 2016. Gross operating margin from crude oil marketing and related activities decreased $83.1 million quarter-to-quarter primarily due to non-cash mark-to-market losses recognized in the third quarter of 2017 compared to mark-to-market gains recognized in the third quarter of 2016, which resulted in a $45.3 million decrease in gross operating margin quarter-to-quarter, and lower sales margins, which accounted for an additional $38.3 million decrease.

Gross operating margin from crude oil operations at our Enterprise Hydrocarbons Terminal ("EHT") decreased $8.5 million quarter-to-quarter primarily due to higher maintenance and other operating costs. Crude oil throughput at the EHT marine docks decreased a net 14 MBPD quarter-to-quarter due in part to the effects of Hurricane Harvey on Houston Ship Channel operations. Gross operating margin from our Cushing, Oklahoma storage terminal decreased $2.3 million quarter-to-quarter primarily due to higher maintenance costs.

Gross operating margin from our equity investment in the Seaway Pipeline decreased $6.9 million quarter-to-quarter primarily due to lower revenues attributable to shipper make-up rights. Crude oil transportation volumes for Seaway were essentially flat quarter-to-quarter; however, import volumes at Seaway's Freeport, Texas marine terminal decreased 52 MBPD quarter-to-quarter primarily due to the effects of Hurricane Harvey.

Gross operating margin from our EFS Midstream System and South Texas Crude Oil Pipeline System increased $20.2 million quarter-to-quarter primarily due to increased deficiency fee revenues associated with shipper volume commitments. Due to decreased producer drilling activity in the Eagle Ford Shale, condensate and crude oil transportation volumes for these systems decreased a combined 15 MBPD quarter-to-quarter and associated natural gas volumes for the EFS Midstream System decreased 85 MMcf/d quarter-to-quarter. Gross operating margin from the South Texas Crude Oil Pipeline System increased $12.7 million quarter-to-quarter primarily due the recognition of $11.4 million of deficiency fee revenues during the third quarter of 2017. Gross operating margin from the EFS Midstream System decreased $12.8 million quarter-to-quarter due to lower throughput volumes; however, this decrease was more than offset by a $22.5 million quarter-to-quarter increase in deficiency fee revenues.

Gross operating margin from our West Texas System and equity investment in the Eagle Ford Crude Oil Pipeline System increased a combined $15.5 million quarter-to-quarter primarily due to an 87 MBPD increase (net to our interest) in crude oil transportation volumes. Crude oil transportation volumes from the West Texas region have increased in connection with higher producer drilling activity across the Permian Basin.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016. Gross operating margin from our Crude Oil Pipelines & Services segment for the nine months ended September 30, 2017 increased a net $58.0 million when compared to the nine months ended September 30, 2016.

Gross operating margin from our West Texas System and equity investment in the Eagle Ford Crude Oil Pipeline System increased a combined $45.5 million period-to-period primarily due to a net 87 MBPD increase in crude oil transportation volumes (net to our interest) from the Permian Basin.

Gross operating margin from our EFS Midstream System increased $22.0 million period-to-period primarily due to increased deficiency fee revenues. Condensate transportation volumes for this system decreased 26 MBPD period-to-period and associated natural gas volumes decreased 118 MMcf/d period-to-period. Gross operating margin for the system decreased $61.0 million period-to-period primarily due to the lower throughput volumes; however, this decrease was more than offset by an $89.2 million period-to-period increase in deficiency fee revenues associated with producer volume commitments. Gross operating margin from our South Texas Crude Oil Pipeline System increased $0.8 million period-to-period primarily due to higher deficiency fee revenues recognized in the third quarter of 2017. Crude oil transportation volumes for this system decreased 25 MBPD period-to-period due to decreased producer drilling activity in South Texas.

Gross operating margin from crude oil marketing and related activities increased $6.6 million period-to-period primarily due to a $50.1 million benefit related to non-cash mark-to-market results, lower pipeline-related costs, which accounted for a $7.9 million increase, and higher earnings from trucking activities, which accounted for a $7.4 million increase, partially offset by lower sales margins, which accounted for a $42.9 million decrease, and lower sales volumes, which accounted for a $15.9 million decrease. Non-cash mark-to-market earnings for this business was a gain of $12.6 million for the first nine months of 2017 versus a loss of $37.5 million for the same period of 2016.

Gross operating margin from our Cushing terminal and crude oil operations at EHT decreased a combined $15.6 million period-to-period primarily due to higher maintenance costs. Crude oil throughput volumes at EHT decreased 27 MBPD period-to-period primarily due to lower export volumes.

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 September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Segment gross operating margin	$ 170.7	$ 178.5	$ 536.0	$ 533.6
Selected volumetric data:				
Natural gas pipeline transportation volumes (BBtus/d)	12,376	12,047	12,084	12,007

Third Quarter of 2017 Compared to Third Quarter of 2016. Gross operating margin from our Natural Gas Pipelines & Services segment for the third quarter of 2017 decreased a net $7.8 million when compared to the third quarter of 2016.

Gross operating margin from our Acadian Gas System decreased $4.7 million quarter-to-quarter primarily due to lower firm capacity reservation revenues on the Haynesville Extension pipeline, which accounted for a $2.0 million decrease, and higher ad valorem taxes and other operating costs, which accounted for an additional $1.1 million decrease. Gross operating margin from our Haynesville Gathering System increased $2.6 million quarter-to-quarter primarily due to higher gathering volumes. When compared to the third quarter of 2016, natural gas volumes handled by our Haynesville Gathering System in the third quarter of 2017 increased 249 BBtus/d and those on our Haynesville Extension pipeline increased 297 BBtus/d.

Gross operating margin from our Texas Intrastate System decreased $2.9 million quarter-to-quarter primarily due to lower average firm transportation fees, which accounted for a $2.8 million decrease, and lower natural gas transportation volumes, which accounted for a $2.6 million decrease, partially offset by a $3.5 million quarter-to-quarter decrease in maintenance and other operating costs. Natural gas transportation volumes for the Texas Intrastate System decreased 406 BBtus/d quarter-to-quarter reflecting reduced drilling activity in the Eagle Ford Shale.

Gross operating margin from the East Texas natural gas pipeline assets we recently acquired from Azure in April 2017 was $1.6 million for the quarter on gathering volumes of 206 BBtus/d.

Gross operating margin from our natural gas marketing activities decreased $1.5 million quarter-to-quarter. Non-cash mark-to-market income for this business was a loss of $2.3 million for the third quarter of 2017 versus a gain of $1.6 million for the third quarter of 2016.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016. Gross operating margin from our Natural Gas Pipelines & Services segment for the nine months ended September 30, 2017 increased a net $2.4 million when compared to the nine months ended September 30, 2016.

Gross operating margin from our Permian Basin Gathering System increased $14.0 million period-to-period primarily due to an increase in compression and treating revenues, which accounted for a $4.8 million increase, higher condensate sales revenues, which accounted for a $3.5 million increase, and a 59 BBtus/d increase in natural gas gathering volumes on the Carlsbad Pipeline, which accounted for an additional $3.5 million increase. Natural gas production in the Permian Basin has increased in connection with a significant rise in crude oil production across West Texas and southeastern New Mexico.

Gross operating margin from our Acadian Gas System increased $8.3 million period-to-period primarily due to $17.4 million of proceeds received in a legal settlement in the second quarter of 2017 for lost revenues and damages associated with the Bayou Corne sinkhole incident caused by third parties in 2012, partially offset by lower firm capacity reservation revenues on the Haynesville Extension pipeline, which accounted for a $7.0 million period-to-period decrease. Gross operating margin from our Haynesville Gathering System increased $3.8 million period-to-period primarily due to higher gathering volumes, which accounted for an $8.6 million increase, partially offset by the effects of lower average gathering fees, which accounted for a $3.3 million decrease. Transportation volumes for the Haynesville Extension pipeline, which is a component of the Acadian Gas System, increased 249 BBtus/d and volumes for the Haynesville Gathering System increased 168 BBtus/d.

Gross operating margin from our natural gas marketing activities increased $7.7 million period-to-period primarily due to an increase in average sales margins, which accounted for a $5.8 million increase, and higher sales volumes, which accounted for an additional $3.2 million increase.

Gross operating margin from the East Texas natural gas pipeline assets we acquired from Azure in April 2017 was $3.2 million on gathering volumes of 205 BBtus/d.

Gross operating margin from our Texas Intrastate System decreased $20.9 million period-to-period primarily due to lower average firm transportation fees, which accounted for a $12.5 million decrease, and lower natural gas transportation volumes, which accounted for an $8.3 million decrease. Natural gas transportation volumes for the Texas Intrastate System decreased 431 BBtus/d period-to-period reflecting reduced drilling activity in the Eagle Ford Shale.

Gross operating margin from our Jonah Gathering System decreased $12.6 million period-to-period primarily due to a 79 BBtus/d decline in natural gas gathering volumes, which accounted for a $5.9 million decrease, and lower average gathering fees, which accounted for an additional $4.7 million decrease.

Petrochemical & Refined Products Services

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Segment gross operating margin:				
Propylene fractionation and related activities	$ 44.5	$ 57.3	$ 175.1	$ 162.2
Butane isomerization and related operations	20.6	16.8	49.7	50.2
Octane enhancement and related plant operations	35.1	16.8	92.6	27.8
Refined products pipelines and related activities	67.6	71.3	213.8	232.4
Marine transportation and other	4.6	9.4	11.4	29.3
Total	$ 172.4	$ 171.6	$ 542.6	$ 501.9
Selected volumetric data:				
Propylene fractionation plant production volumes (MBPD)	78	76	80	75
Butane isomerization volumes (MBPD)	110	113	106	112
Standalone DIB processing volumes (MBPD)	82	85	82	90
Octane additive and related plant production volumes (MBPD)	24	27	25	19
Pipeline transportation volumes, primarily refined products and petrochemicals (MBPD)	778	784	801	836
Refined products and petrochemical marine terminal volumes (MBPD)	359	354	410	381

Propylene fractionation and related activities

Third Quarter of 2017 Compared to Third Quarter of 2016. Gross operating margin from propylene fractionation and related marketing activities for the third quarter of 2017 decreased a net $12.8 million when compared to the third quarter of 2016. Gross operating margin from our Mont Belvieu propylene fractionation plants decreased $8.4 million quarter-to-quarter primarily due to higher operating costs. Start-up costs attributable to the PDH facility, which are reflected in gross operating margin for propylene fractionation and related activities, increased $2.9 million quarter-to-quarter. Our PDH facility is expected to commence operations during the fourth quarter of 2017.

Based on our analysis of the effects of Hurricane Harvey, we believe that actual third quarter of 2017 results from propylene fractionation and related marketing activities were approximately $7.5 million lower than we expected primarily due to lower than anticipated volumes and lost business opportunities.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016. Gross operating margin from propylene fractionation and related marketing activities for the nine months ended September 30, 2017 increased a net $12.9 million when compared to the nine months ended September 30, 2016.

Gross operating margin from our Mont Belvieu propylene fractionation plants increased a net $27.5 million period-to-period primarily due to higher propylene sales volumes, which accounted for a $16.6 million increase, higher average propylene sales margins, which accounted for a $14.9 million increase, and higher average propylene fractionation fees, which accounted for an additional $11.2 million increase, partially offset by an increase in maintenance, storage and other operating costs of $16.9 million.

Start-up costs attributable to the PDH facility increased $6.7 million period-to-period.

Gross operating margin from our propylene export marine terminal decreased a net $2.3 million period-to-period primarily due to lower average loading fees, which accounted for a $7.3 million decrease, partially offset by lower operating costs, which accounted for a $3.9 million increase. Gross operating margin from our Mont Belvieu rail terminal decreased $2.1 million period-to-period primarily due to lower volumes of 5 MBPD.

Isomerization and related operations

Third Quarter of 2017 Compared to Third Quarter of 2016. Gross operating margin from butane isomerization and deisobutanizer ("DIB") operations for the third quarter of 2017 increased $3.8 million when compared to the third quarter of 2016 primarily due to lower power and maintenance costs. Isomerization volumes decreased 6 MBPD quarter-to-quarter due in part to the effects of Hurricane Harvey.

Based on our analysis of the effects of Hurricane Harvey, we believe that actual third quarter of 2017 results from isomerization were approximately $4.9 million lower than we expected primarily due to lower than anticipated volumes.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016. Gross operating margin from butane isomerization and DIB operations for the nine months ended September 30, 2017 decreased $0.5 million when compared to the nine months ended September 30, 2016 primarily due to higher maintenance costs on related pipeline infrastructure.

Octane enhancement and related operations

Third Quarter of 2017 Compared to Third Quarter of 2016. Gross operating margin from our octane enhancement facility and high purity isobutylene ("HPIB") plant for the third quarter of 2017 increased $18.3 million when compared to the third quarter of 2016. Gross operating margin from our octane enhancement facility increased $18.6 million quarter-to-quarter primarily due to lower major maintenance costs, which accounted for an $11.1 million increase, and higher average sales margins, which accounted for a $10.3 million increase. Plant production volumes decreased 3 MBPD quarter-to-quarter due in part to the effects of Hurricane Harvey.

Based on our analysis of the effects of Hurricane Harvey, we believe that actual third quarter of 2017 results from octane enhancement were approximately $5.4 million lower than we expected primarily due to lower than anticipated volumes.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016. Gross operating margin from our octane enhancement facility and HPIB plant for the nine months ended September 30, 2017 increased $64.8 million when compared to the nine months ended September 30, 2016. Gross operating margin from our octane enhancement facility increased $66.2 million period-to-period primarily due to lower major maintenance costs, which accounted for $32.1 million of the increase, higher sales volumes, which accounted for a $25.7 million increase, and higher average sales margins, which accounted for a $15.6 million increase.

Historically, our octane enhancement plant experienced downtime annually for major maintenance activities. During 2016, we completed modifications to our octane enhancement plant to alleviate the need for such yearly outages. We now expect downtime for major maintenance activities at our octane enhancement plant once every three years. As a result of these modifications, plant production volumes increased 4 MBPD period-to-period.

Refined products pipelines and related activities

Third Quarter of 2017 Compared to Third Quarter of 2016. Gross operating margin from refined products pipelines and related marketing activities for the third quarter of 2017 decreased $3.7 million when compared to the third quarter of 2016.

Gross operating margin from our refined products terminals along the TE Products Pipeline decreased $7.4 million quarter-to-quarter primarily due to the recognition of $7.1 million of gains in connection with legal settlements during the third quarter of 2016. Gross operating margin from our Beaumont and Houston Ship Channel refined products marine terminals decreased a combined $4.8 million quarter-to-quarter primarily due to lower storage revenues.

Gross operating margin from our TE Products Pipeline increased $3.4 million quarter-to-quarter primarily due to higher average transportation fees, which accounted for a $3.9 million increase, and higher transportation volumes, which accounted for a $3.1 million increase, partially offset by lower product sales revenues, which accounted for a $3.7 million decrease. Transportation volumes for the TE Products Pipeline increased 11 MBPD quarter-to-quarter primarily due to higher intrastate refined products and NGL movements during the third quarter of 2017.

Gross operating margin from refined products marketing increased $2.9 million quarter-to-quarter primarily due to higher average refined products sales margins, which accounted for a $6.6 million increase, partially offset by a $3.7 million quarter-to-quarter decrease in mark-to-market income.

Based on our analysis of the effects of Hurricane Harvey, we believe that actual third quarter of 2017 results from refined products pipelines and terminals were approximately $7.4 million lower than we expected primarily due to lower than anticipated volumes.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016. Gross operating margin from refined products pipelines and related marketing activities for the nine months ended September 30, 2017 decreased $18.6 million when compared to the nine months ended September 30, 2016.

Gross operating margin from refined products marketing decreased $13.1 million period-to-period primarily due to lower average refined products sales margins, which accounted for a $20.3 million decrease, partially offset by a $5.9 million period-to-period increase in non-cash mark-to-market income.

Gross operating margin from our refined products terminals along the TE Products Pipeline decreased $5.0 million period-to-period primarily due to the recognition of $7.1 million of gains in connection with legal settlements during the third quarter of 2016.

Marine transportation and other

Third Quarter of 2017 Compared to Third Quarter of 2016. Gross operating margin from our marine transportation business for the third quarter of 2017 decreased $4.8 million when compared to the third quarter of 2016 primarily due to lower average fees, which are generally attributable to increased competition within this line of business. Our marine transportation assets are used to transport refined and other petroleum products along key U.S. inland and Intracoastal Waterway systems.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016. Gross operating margin from marine transportation and other for the nine months ended September 30, 2017 decreased $17.9 million when compared to the nine months ended September 30, 2016. Gross operating margin attributable to our marine transportation business decreased $14.6 million period-to-period primarily due to lower average fees.

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 September 30, 2017, we had $3.62 billion of consolidated liquidity, which was comprised of $3.59 billion of available borrowing capacity under EPO's revolving credit facilities and $32.9 million of unrestricted cash on hand.

We expect to issue additional equity and debt securities to assist us in meeting our future funding and liquidity requirements, including those related to capital spending.

Consolidated Debt

The following table presents scheduled maturities of our consolidated debt obligations outstanding at September 30, 2017 for the years indicated (dollars in millions):

		Scheduled Maturities of Debt					
	Total	**Remainder of 2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**
Commercial Paper Notes	$ 1,910.0	$ 1,910.0	$ --	$ --	$ --	$ --	$ --
Senior Notes	19,850.0	--	1,100.0	1,500.0	1,500.0	575.0	15,175.0
Junior Subordinated Notes	3,174.4	--	--	--	--	--	3,174.4
Total	$ 24,934.4	$ 1,910.0	$ 1,100.0	$ 1,500.0	$ 1,500.0	$ 575.0	$ 18,349.4

As noted under "Significant Recent Developments" within this Part I, Item 2, EPO issued $1.7 billion aggregate principal amount of junior subordinated notes (Junior Notes D and E) in August 2017 and entered into new revolving credit agreements in September 2017 (the Multi-Year Revolving Credit Facility and 364-Day Revolving Credit Agreement). As of the filing date of this quarterly report, there were no borrowings outstanding under the new revolving credit facilities.

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.

Issuance of Common Units

The following table summarizes the issuance of common units in connection with our at-the-market ("ATM") program, DRIP and employee unit purchase plan ("EUPP") for the quarterly periods indicated (dollars in millions, number of units issued as shown):

	Number of Common Units Issued	**Net Cash Proceeds Received**
Three months ended March 31, 2017:		
Common units issued in connection with ATM program	12,865,371	$ 356.0
Common units issued in connection with DRIP and EUPP	3,440,559	92.8
Total common units issued for quarter	16,305,930	448.8
Three months ended June 30, 2017:		
Common units issued in connection with ATM program	7,991,635	215.8
Common units issued in connection with DRIP and EUPP	3,595,122	92.6
Total common units issued for quarter	11,586,757	308.4
Three months ended September 30, 2017:		
Common units issued in connection with ATM program	950,720	25.5
Common units issued in connection with DRIP and EUPP	3,674,908	94.5
Total common units issued for quarter	4,625,628	120.0
Total common units issued during the nine months ended September 30, 2017	32,518,315	$ 877.2

ATM Program

We have a registration statement on file with the SEC covering the issuance of up to $1.89 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings in connection with our ATM program. After taking into account the aggregate sales price of common units sold under the ATM program through September 30, 2017, we have the capacity to issue additional common units under the ATM program up to an aggregate sales price of $838.6 million. We expect to file a routine update to our ATM program in November 2017 to increase the aggregate available capacity under this program to approximately $2.5 billion. This step would provide us with additional long-term flexibility should the need arise. The need for future issuances under the ATM program would be evaluated in light of management's desire to self-fund the equity portion of growth capital spending by 2019.

DRIP and EUPP
We also have registration statements on file with the SEC collectively authorizing the issuance of up to 240,000,000 of our common units in connection with our DRIP. After taking into account the number of common units issued under the DRIP through September 30, 2017, we have the capacity to issue an additional 88,912,840 common units under this plan.

The partnership's 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 common units at discounts up to 5 percent. In November 2017, management set the discount rate at 2.5 percent beginning with the distribution declared with respect to the fourth quarter of 2017 expected to be paid in February 2018. The discount rate was previously 5 percent.

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 EUPP. After taking into account the number of common units issued under the EUPP through September 30, 2017, we have the capacity to issue an additional 5,900,541 common units under this plan.

Use of Proceeds
The net cash proceeds we received from the issuance of common units during the nine months ended September 30, 2017 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and for general company purposes.

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

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 margin requirements change.

At September 30, 2017 and December 31, 2016, our restricted cash amounts were $66.8 million and $354.5 million, respectively. The balance of restricted cash decreased since December 31, 2016 primarily due to the settlement of derivative instruments related to marketing positions during the first quarter of 2017. For information regarding our derivative instruments and hedging activities, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Credit Ratings
As of October 31, 2017, the investment-grade credit ratings of EPO's long-term senior unsecured debt securities were BBB+ from Standard and Poor's and Baa1 from Moody's. In addition, the credit ratings of EPO's short-term senior unsecured debt securities were A-2 from Standard and Poor's and P-2 from Moody's. Fitch Ratings issued non-solicited ratings of BBB+ and F-2 for EPO's long-term senior unsecured debt securities and short-term senior unsecured debt securities, respectively.

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

Cash Flows from Operating, Investing and Financing Activities

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

	For the Nine Months Ended September 30, 2017	For the Nine Months Ended September 30, 2016
Net cash flows provided by operating activities	$ 2,819.9	$ 2,659.0
Cash used in investing activities	2,016.2	3,695.7
Cash provided by (used in) financing activities	(833.9)	1,074.8

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, petrochemical 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 customers 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 2016 Form 10-K.

Comparison of Nine Months Ended September 30, 2017 with Nine Months Ended September 30, 2016

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

Operating activities. Net cash flows provided by operating activities for the nine months ended September 30, 2017 increased $160.9 million when compared to the nine months ended September 30, 2016. The increase in cash provided by operating activities was primarily due to:

- a $148.7 million increase in cash resulting from higher partnership earnings in the nine months ended September 30, 2017 compared to the same period in 2016 (after adjusting our $175.0 million period-to-period increase in net income for changes in the non-cash items identified on our Unaudited Condensed Statements of Consolidated Cash Flows); and

- a $34.6 million period-to-period increase in cash distributions received on earnings from unconsolidated affiliates primarily due to our investments in crude oil pipeline joint ventures; partially offset by

- a $22.4 million period-to-period decrease in cash primarily due to the timing of cash receipts and payments related to operations.

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

Investing activities. Cash used for investing activities in the nine months ended September 30, 2017 decreased $1.68 billion when compared to the same period in 2016 primarily due to:

- an $801.3 million period-to-period decrease in cash used for business combinations, net of cash received. During the nine months ended September 30, 2017, net cash used for business combinations was $198.7 million, which was primarily related to the Azure acquisition. During the same period in 2016, $1.0 billion was paid for the second and final installment for the acquisition of EFS Midstream LLC;

- a $549.1 million period-to-period beneficial change in restricted cash, which was an inflow of $287.7 million during the first nine months of 2017 compared to a cash outflow of $261.4 million during the same period in 2016; and

- a $291.6 million period-to-period decrease in capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs (see "Capital Spending" within this Part I, Item 2 for additional information regarding our capital spending program).

Financing activities. Cash used in financing activities for the nine months ended September 30, 2017 was $833.9 million compared to cash provided by financing activities of $1.07 billion for the nine months ended September 30, 2016. The $1.91 billion period-to-period change in cash flow from financing activities was primarily due to:

- a $1.29 billion period-to-period decrease in net cash proceeds from the issuance of common units. We issued an aggregate 32,518,315 common units, which generated $877.2 million of net cash proceeds, in connection with our ATM program, DRIP and EUPP during the nine months ended September 30, 2017. This compares to an aggregate 89,448,050 common units we issued in connection with these programs and plans during the same period in 2016, which collectively generated $2.17 billion of net cash proceeds;

- a $390.1 million period-to-period decrease in net cash inflows attributable to our consolidated debt obligations primarily due to the issuance of $1.7 billion in principal amount of junior subordinated notes and repayment of $800.0 million in principal amount of senior notes during the nine months ended September 30, 2017 compared to the issuance of $1.25 billion and repayment of $750.0 million in principal amount of senior notes during the nine months ended September 30, 2016. In addition, net issuances under EPO's commercial paper program decreased $796.6 million period-to-period; and

- a $212.1 million period-to-period increase in cash distributions paid to limited partners during the nine months ended September 30, 2017 when compared to the same period in 2016. 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.

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.

In October 2017, the Board declared a cash distribution of $0.4225 per common unit with respect to the third quarter of 2017. In addition, our management announced plans to recommend to the Board additional quarterly cash distribution increases of $0.0025 per unit with respect to the fourth quarter of 2017 and each of the four quarters of 2018. For additional information regarding our expected distribution growth rate, see "Significant Recent Developments" within this Item 2.

We measure available cash by reference to "distributable cash flow," which is a non-GAAP liquidity measure. 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. 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.

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 several other master limited partnerships, our general partner has a non-economic ownership interest in us and is not entitled to receive any cash distributions from us based on incentive distribution rights or other equity interests.

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, which is the most comparable GAAP measure. For a discussion of net cash flows provided by operating activities, see the previous section titled "Cash Flows from Operating, Investing and Financing Activities" within this Item 2.

The following table summarizes our calculation of distributable cash flow for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Net income attributable to limited partners (1)	$ 610.9	$ 634.6	$ 2,025.3	$ 1,854.3
Adjustments to GAAP net income attributable to limited partners to derive non-GAAP distributable cash flow:				
Add depreciation, amortization and accretion expenses	412.6	391.9	1,221.4	1,155.3
Add non-cash asset impairment and related charges	10.0	6.8	35.2	29.1
Subtract net gains attributable to asset sales	(1.1)	(8.9)	(1.1)	(2.3)
Add cash proceeds from asset sales (2)	3.0	16.0	6.2	43.9
Add or subtract changes in fair market value of derivative instruments	29.7	(26.2)	(14.2)	42.1
Add changes in fair value of Liquidity Option Agreement (3)	8.9	6.9	33.0	28.0
Add cash distributions received from unconsolidated affiliates (4)	123.1	99.0	353.0	333.5
Add monetization of interest rate derivative instruments accounted for as cash flow hedges	30.6	--	30.6	--
Subtract equity in income of unconsolidated affiliates	(113.4)	(92.3)	(315.2)	(269.8)
Subtract sustaining capital expenditures (5)	(53.8)	(61.7)	(164.1)	(179.4)
Add deferred income tax expense or subtract benefit, as applicable	0.4	1.0	1.1	5.3
Other, net	4.0	11.3	34.2	31.7
Distributable cash flow	$ 1,064.9	$ 978.4	$ 3,245.4	$ 3,071.7
Total cash distributions paid to limited partners with respect to period	$ 913.4	$ 855.4	$ 2,712.8	$ 2,521.8
Cash distributions per unit declared by Enterprise GP with respect to period (6)	$ 0.4225	$ 0.4050	$ 1.2575	$ 1.200
Total distributable cash flow retained by partnership with respect to period (7)	$ 151.5	$ 123.0	$ 532.6	$ 549.9
Distribution coverage ratio (8)	1.17x	1.14x	1.20x	1.22x

(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) For information regarding the Liquidity Option Agreement, see Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

(4) 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.

(5) Sustaining capital expenditures are presented on an accrual basis.

(6) 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. In addition, see "Significant Recent Developments" within this Part I, Item 2 for information regarding the anticipated growth rate of future cash distributions through the end of 2018.

(7) At the sole discretion of Enterprise GP, cash retained by the partnership with respect to each of these years was primarily reinvested in our growth capital spending program, which substantially reduced our reliance on the equity and debt capital markets to fund such major expenditures.

(8) Distribution coverage ratio 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.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Net cash flows provided by operating activities	$ 485.0	$ 813.8	$ 2,819.9	$ 2,659.0
Adjustments to reconcile net cash flows provided by operating activities to distributable cash flow:				
Subtract sustaining capital expenditures	(53.8)	(61.7)	(164.1)	(179.4)
Add cash proceeds from asset sales	3.0	16.0	6.2	43.9
Add monetization of interest rate derivative instruments accounted for as cash flow hedges	30.6	--	30.6	--
Net effect of changes in operating accounts	594.2	195.1	512.1	489.7
Other, net	5.9	15.2	40.7	58.5
Distributable cash flow	$ 1,064.9	$ 978.4	$ 3,245.4	$ 3,071.7

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 well 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.

We began commercial service on approximately $280 million of major growth capital projects during the nine months ended September 30, 2017, including expansions related to our propylene pipeline system and Beaumont refined products terminal. We recently completed construction of the Midland-to-Sealy segment of our Midland-to-ECHO Pipeline System and expect this pipeline to be placed into limited service in late November 2017. The Midland-to-Sealy pipeline is expected to be in full service, including batching capabilities, during the second quarter of 2018. Hurricane Harvey delayed the commissioning schedule for our PDH facility by approximately four weeks. We are now in the final stages of commissioning and expect initial production of polymer grade propylene from this facility during the fourth quarter of 2017. In addition, we have approximately $9.1 billion of growth capital projects scheduled to be completed by 2020 including our iBDH facility, the Shin Oak NGL pipeline, our ninth NGL fractionator in Mont Belvieu and the completion of joint venture-owned dock infrastructure in Corpus Christi designed to accommodate crude oil volumes.

After taking into account our capital spending through the third quarter of 2017, we currently expect to invest in the range of $2.9 billion to $3.1 billion for growth capital projects for the full year of 2017, including the $191.4 million we paid in connection with the Azure acquisition, and approximately $240 million for sustaining capital expenditures. Our expectation for spending on growth capital projects for the fourth quarter of 2017 is approximately $750 million to $950 million and for sustaining capital expenditures is approximately $80 million. Our forecast of capital spending for 2017 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 Nine Months Ended September 30,	
	2017	**2016**
Capital spending for property, plant and equipment, net: (1)		
Growth capital projects (2)	$ 1,953.8	$ 2,221.9
Sustaining capital projects (3)	164.4	187.9
Cash used for business combinations, net (4)	198.7	1,000.0
Investments in unconsolidated affiliates	32.8	119.9
Other investing activities	--	0.4
Total capital spending	$ 2,349.7	$ 3,530.1

(1) Growth and sustaining capital amounts presented in the table above are presented on a cash basis and net of related contributions in aid of construction costs.

(2) Growth capital projects either (a) result in new sources of cash flow due to enhancements of or additions to existing assets (e.g., additional revenue streams, cost savings resulting from debottlenecking of a facility, etc.) or (b) expand our asset base through construction of new facilities that will generate additional revenue streams and cash flows.

(3) Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues or result in significant cost savings.

(4) Amount for the nine months ended September 30, 2017 primarily represents net cash used for the acquisition of Azure in April 2017. Amount for the nine month ended September 30, 2016 represents the second payment for EFS Midstream LLC in July 2016. We acquired EFS Midstream LLC in July 2015 for approximately $2.1 billion in cash, which was payable in two installments.

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 nine months ended September 30, 2017 involved projects at our Mont Belvieu complex as well as projects to support crude oil, natural gas and NGL production from the Permian Basin. 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 Nine Months Ended September 30, 2017 with Nine Months Ended September 30, 2016

Total capital spending decreased $1.2 billion period-to-period primarily due to reduced cash used for business combinations, which accounted for an $801.3 million decrease, and reduced spending on growth capital projects, which accounted for an additional $268.1 million decrease. Of the period-to-period decrease in cash used for business combinations and growth capital spending, the significant elements are as follows:

- Net cash used for business combinations decreased $801.3 million period-to-period due to the second payment made in July 2016 for EFS Midstream LLC, which accounted for $1.0 billion of the decrease, partially offset by $191.4 million in net cash paid in connection with the Azure acquisition made in April 2017;

- Growth capital spending at our Morgan's Point Ethane Export Terminal and at EHT for LPG export-related expansion projects decreased a combined $262.7 million period-to-period. In September 2016, we placed our Morgan's Point Ethane Export Terminal into service;

- Growth capital spending at our Mont Belvieu complex decreased $207.4 million period-to-period primarily due to lower spending for our PDH facility, which accounted for a $276.0 million decrease, partially offset by higher growth capital spending for our ninth NGL fractionator at our Mont Belvieu, Texas Complex, which accounted for a $75.7 million increase. As noted earlier, our PDH facility is expected to be placed into service during the fourth quarter of 2017. The ninth NGL fractionator, which resumed construction in March 2017 in anticipation of increased NGL production from the Permian Basin, is expected to be completed by mid-2018;

- Growth capital spending for crude oil assets at our EHT, Beaumont Marine West and ECHO terminals decreased a combined $142.6 million period-to-period primarily due to the completion of new storage tanks and related assets at these facilities during 2016;

- Investments in unconsolidated affiliates decreased $87.1 million period-to-period primarily due to completion of our Waha natural gas processing plant in August 2016, which accounted for a $41.1 million decrease, and reduced spending on joint venture-owned crude oil pipelines and dock infrastructure, which accounted for an additional $35.8 million decrease; partially offset by

- Growth capital spending for projects to support Permian Basin production increased $499.9 million period-to-period. We are in various stages of completion on multiple projects to support crude oil, natural gas and NGL production in the Permian Basin, including our Orla natural gas processing plants and related pipelines, Shin Oak NGL Pipeline and Midland-to-ECHO Pipeline System.

Pipeline Integrity Program

Our pipelines operate under safety regulations administered by the U.S. Department of Transportation ("DOT") that requirement pipeline integrity management programs for hazardous liquid and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
Recognized in operating costs and expenses	$ 8.7	$ 9.1	$ 41.0	$ 46.3
Reflected as a component of sustaining capital expenditures	11.2	15.6	32.5	32.7
Total	$ 19.9	$ 24.7	$ 73.5	$ 79.0

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2016 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

Contractual Obligations

Our consolidated principal debt obligations at September 30, 2017 were approximately $24.93 billion compared to $23.90 billion at December 31, 2016. 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.

Recent Accounting Developments

<u>Revenue Recognition</u>. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Codification 606, *Revenues from Contracts with Customers* ("ASC 606"). The new accounting standard, along with its related amendments, replaces the current rules-based U.S. GAAP governing revenue recognition with a principles-based approach. We plan to adopt the new standard on January 1, 2018.

Our implementation activities related to ASC 606 are nearly complete. For the vast majority of our businesses, we will not have any material differences in the amount or timing of revenues once we adopt ASC 606. However, based on guidance in ASC 606 applicable to non-cash consideration, we will start recognizing revenue in connection with equity NGL volumes we receive as consideration for providing processing services under percent of liquids and similar arrangements. The value assigned to this non-cash consideration and related inventory will be based on the fair value of NGLs we are entitled to at the time the processing services are performed. An additional revenue stream, along with the related cost of sales, would be recognized in connection with the ultimate sale of the NGL products derived from the NGLs acquired as a fee for service. Under current accounting practice, we only recognize revenue from the downstream sale of NGL products and do not record service revenue. Based on initial estimates, the changes required by ASC 606 are expected to result in less than a 5 percent increase in our total consolidated revenues.

Given the rapid turnover of our inventories of NGL products each month, we do not expect a significant change in our gross operating margin from natural gas processing and related NGL marketing activities as a result of the changes required by ASC 606. The additional revenue stream recognized in connection with receipt of the equity NGLs will be offset by an equal cost of sales amount when the associated NGL products are sold, which is expected to typically be completed in the same accounting period.

As a result of adopting the new standard, there will be significant changes to our disclosures based on the additional requirements prescribed by ASC 606. These new disclosures include information regarding the significant judgments used in evaluating when and how revenue is (or will be) recognized and data related to contract assets and liabilities. Additionally, we are revising our business processes, systems and controls to ensure the accuracy and timeliness of the recognition and disclosure requirements under the new revenue guidance.

<u>Leases</u>. In February 2016, the FASB issued ASC 842, *Leases* ("ASC 842"), which requires substantially all leases (with the exception of leases with a term of one year or less) to be recorded on the balance sheet using a method referred to as the right-of-use asset approach. We plan to adopt the new standard on January 1, 2019.

We have started the process of reviewing our lease agreements in light of the new guidance. Although we are in the early stages of our ASC 842 implementation project, we anticipate that this new lease guidance will cause significant changes to the way leases are recorded, presented and disclosed in our consolidated financial statements.

Derivative Instruments. In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*, which amends and simplifies existing guidance in order to allow companies to more accurately present the economic effects of risk management activities in the financial statements. We are currently evaluating the impact of this guidance on our consolidated financial statements and the timing of our planned adoption.

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

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 2016 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 economic value (or fair value) of the derivative instrument portfolio based on a hypothetical 10 percent change in the underlying interest rates or quoted market prices on a particular day. In addition to these variables, the economic 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 economic 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.

In addition, the fair value amounts presented in the sensitivity analysis tables below do not reflect any rule changes made by certain exchanges (e.g., the Chicago Mercantile Exchange) that may impact the financial statement or disclosure presentation for a derivative instrument since such rule changes have no impact on the underlying contractual terms of the derivative instrument itself, including the timing or price of the ultimate settlement.

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 September 30, 2017 (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)	3.9	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	1.0	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchase of NGLs (MMBbls)	0.1	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	0.2	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	1.0	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	4.5	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	61.8	0.2	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	95.5	2.8	Cash flow hedge
NGLs inventory management activities (MMBbls)	0.4	n/a	Fair value hedge
Refined products marketing:			
Forecasted sales of refined products (MMBbls)	0.1	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	1.5	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	1.6	0.1	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	8.0	0.1	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (4,5)	91.7	17.4	Mark-to-market
NGL risk management activities (MMBbls) (5)	15.0	n/a	Mark-to-market
Refined products risk management activities (MMBbls) (5)	0.1	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	64.5	16.3	Mark-to-market

(6) 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.

(7) 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 2018, March 2018 and March 2020, respectively.

(8) Forecasted NGL sales volumes under Natural gas processing exclude 0.2 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.

(9) Current and long-term volumes include 41.9 Bcf and 7.7 Bcf, respectively, of physical derivative instruments that are predominantly priced at a market-based index plus a premium or minus a discount related to location differences.

(10) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

At September 30, 2017, 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 derivative instruments and related contracts.

- The objective of our natural gas processing hedging program is to hedge an amount of earnings associated with these activities. We achieve this objective by executing fixed-price sales for a portion of our expected equity NGL production using derivative instruments and related contracts. 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 using derivative instruments and related contracts.

- 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 derivative instruments and related contracts.

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

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2016**	**September 30, 2017**	**October 16, 2017**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (5.3)	$ (2.8)	$ (5.4)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(9.7)	(5.7)	(8.4)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(0.9)	0.2	(2.4)

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated economic 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, 2016**	**September 30, 2017**	**October 16, 2017**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (150.3)	$ (232.4)	$ (228.4)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(227.7)	(333.4)	(324.4)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(73.0)	(131.4)	(132.4)

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

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2016**	**September 30, 2017**	**October 16, 2017**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (42.4)	$ (31.0)	$ (19.8)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(80.0)	(79.5)	(61.6)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(4.7)	17.6	22.0

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 economic 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 September 30, 2017 (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 1.79%	Fair value hedge

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

		Interest Rate Swap Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2016	September 30, 2017	October 16, 2017
Fair value assuming no change in underlying interest rates	*Asset (Liability)*	$ (0.8)	$ (1.6)	$ (1.6)
Fair value assuming 10% increase in underlying interest rates	*Asset (Liability)*	(2.0)	(2.1)	(2.2)
Fair value assuming 10% decrease in underlying interest rates	*Asset (Liability)*	0.4	(1.0)	(1.1)

The following table summarizes our portfolio of 30-year forward starting swaps outstanding at September 30, 2017. Forward starting swaps hedge the expected underlying benchmark interest rates related to future issuances of debt.

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Expected Settlement Date	Average Rate Locked	Accounting Treatment
Future long-term debt offering	3 forward starting swaps	$275.0	2/2019	2.57%	Cash flow hedge

As a result of market conditions in August 2017, we elected to terminate four forward starting swaps that were scheduled to settle in May 2018, which resulted in cash gains totaling $30.6 million. As cash flow hedges, gains on these derivative instruments will be reflected as a component of accumulated other comprehensive income and be amortized to earnings (as a decrease in interest expense) over the life of the associated future debt obligations beginning in May 2018.

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

		Forward Starting Swap Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2016	September 30, 2017	October 16, 2017
Fair value assuming no change in underlying interest rates	*Asset (Liability)*	$ 36.2	$ 0.8	$ (0.6)
Fair value assuming 10% increase in underlying interest rates	*Asset (Liability)*	49.3	14.8	13.9
Fair value assuming 10% decrease in underlying interest rates	*Asset (Liability)*	22.1	(14.2)	(15.6)

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 third quarter of 2017, 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 2016 Form 10-K, in addition to other information in such annual report. The risk factors set forth in our 2016 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 nine months ended September 30, 2017 in connection with the vesting of restricted and phantom unit awards:

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
Vesting of restricted common unit awards:				
February 2017 (1)	225,751	$ 28.77	--	--
May 2017 (2)	742	$ 27.45	--	--
August 2017 (3)	3,026	$ 26.58	--	--
Vesting of phantom unit awards:				
February 2017 (4)	720,393	$ 28.82	--	--
March 2017 (5)	147	$ 27.58	--	--
May 2017 (6)	39,653	$ 27.40	--	--
August 2017 (7)	17,003	$ 27.00	--	--

(1) Of the 665,920 restricted common unit awards that vested in February 2017 and converted to common units, 225,751 units were sold back to us by employees to cover related withholding tax requirements.

(2) Of the 2,550 restricted common unit awards that vested in May 2017 and converted to common units, 742 units were sold back to us by employees to cover related withholding tax requirements.

(3) Of the 10,900 restricted common unit awards that vested in August 2017 and converted to common units, 3,026 units were sold back to us by employees to cover related withholding tax requirements.

(4) Of the 2,233,617 phantom unit awards that vested in February 2017 and converted to common units, 720,393 units were sold back to us by employees to cover related withholding tax requirements.

(5) Of the 450 phantom unit awards that vested in March 2017 and converted to common units, 147 units were sold back to us by employees to cover related withholding tax requirements.

(6) Of the 117,369 phantom unit awards that vested in May 2017 and converted to common units, 39,653 units were sold back to us by employees to cover related withholding tax requirements.

(7) Of the 61,634 phantom unit awards that vested in August 2017 and converted to common units, 17,003 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 Enterprise GP in October 2014, as the designee of Marquard & Bahls AG ("M&B"), in connection with our acquisition of Oiltanking Partners, L.P. ("Oiltanking"). Dr. Flach is also the Chief Executive Officer of M&B and a member of the M&B executive board.

M&B owns and controls Oiltanking GmbH, which in turn owns a joint venture interest in the Exir Chemical Terminal ("ECT") in Iran via its wholly owned affiliates Oiltanking Iran GmbH (formerly named Oiltanking Odfjell GmbH) and OMEA GmbH. This interest results from an investment dating back to 2002. Oiltanking GmbH currently has the contractual right to vote for the appointment of two members 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.

ECT stores chemicals and hydrocarbons, including naphtha, linear alkyl benzene and n-hexane, for distribution in Iran and for export to Asia and Europe. To our knowledge, ECT's activities are in compliance with applicable 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 the National Petrochemical Company ("NPC"), which operates the berth. Petzone is a subsidiary of NPC, 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	Amendment No. 1 to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC, dated effective as of April 26, 2017 (incorporated by reference to Exhibit 3.1 to Form 8-K filed May 2, 2017).
3.10	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).
3.11	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).

3.12	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 14, 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	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).
4.8	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).
4.9	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).
4.10	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).
4.11	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).
4.12	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).
4.13	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).

4.14	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).
4.15	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).
4.16	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).
4.17	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).
4.18	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).
4.19	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).
4.20	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).
4.21	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).
4.22	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).
4.23	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).
4.24	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).
4.25	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).
4.26	Twenty-Ninth Supplemental Indenture, dated as of August 16, 2017, 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 August 16, 2017).
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 A to Exhibit 4.3 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 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
4.30	Form of Global Note representing $300.0 million principal amount of Junior Subordinated Notes due 2066 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.31	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).
4.32	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 A to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.33	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 A to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.34	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 B to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.35	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 D to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.36	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 E to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.37	Form of Global Note representing $285.8 million principal amount of Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.38	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 B to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.39	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 C to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.40	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 A to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.41	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 B to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.42	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 A to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.43	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 B to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.44	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 A to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
4.45	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 B to Exhibit 4.3 to Form 8-K filed August 13, 2012).

4.46	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 A to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.47	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 B to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.48	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 A to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.49	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 B to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.50	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 A to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.51	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 B to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.52	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 C to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.53	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 B to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.54	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 A to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.55	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 B to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.56	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 C to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.57	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 A to Exhibit 4.4 to Form 8-K filed April 13, 2016).
4.58	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 B to Exhibit 4.4 to Form 8-K filed April 13, 2016).
4.59	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 C to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.60	Form of Global Note representing $700 million principal amount of Junior Subordinated Notes D due 2077 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed August 16, 2017).
4.61	Form of Global Note representing $1.0 billion principal amount of Junior Subordinated Notes E due 2077 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed August 16, 2017).
4.62	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).
4.63	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).

4.64	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).
4.65	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).
4.66	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).
4.67	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).
4.68	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).
4.69	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).
4.70	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).
4.71	Sixth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.12 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.72	Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.13 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.73	Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.74	Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed March 1, 2010).

4.75	Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007).
4.76	First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007).
4.77	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).
4.78	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).
4.79	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 March 1, 2010).
4.80	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 October 1, 2014).
10.1	364-Day Revolving Credit Agreement, dated as of September 13, 2017, among Enterprise Products Operating LLC, the Lenders party thereto, Citibank, N.A. as Administrative Agent, Wells Fargo Bank, National Association, DNB Bank ASA, New York Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, Ltd. and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Syndication Agents, and Barclays Bank PLC, Royal Bank of Canada, Sumitomo Mitsui Banking Corporation, SunTrust Bank, The Bank of Nova Scotia and The Toronto-Dominion Bank, New York Branch, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 15, 2017).
10.2	Guaranty Agreement, dated as of September 13, 2017, by Enterprise Products Partners L.P. in favor of Citibank, N.A., as administrative agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed September 15, 2017).
10.3	Revolving Credit Agreement, dated as of September 13, 2017, among Enterprise Products Operating LLC, the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent, Citibank, N.A., DNB Bank ASA, New York Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, Ltd. and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Syndication Agents, and Barclays Bank PLC, Royal Bank of Canada, Sumitomo Mitsui Banking Corporation, SunTrust Bank, The Bank of Nova Scotia and The Toronto-Dominion Bank, New York Branch, as Co-Documentation Agents (incorporated by reference to Exhibit 10.3 to Form 8-K filed September 15, 2017).
10.4	Guaranty Agreement, dated as of September 13, 2017, by Enterprise Products Partners L.P. in favor of Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.4 to Form 8-K filed September 15, 2017).
12.1#	Computation of ratio of earnings to fixed charges for the nine months ended September 30, 2017 and each of the years ended December 31, 2016, 2015, 2014, 2013 and 2012.

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 nine months ended September 30, 2017.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the nine months ended September 30, 2017.
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 nine months ended September 30, 2017.
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 nine months ended September 30, 2017.
32.2#	Sarbanes-Oxley Section 906 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the nine months ended September 30, 2017.
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 nine months ended September 30, 2017.
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 November 6, 2017.

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

By: Enterprise Products Holdings LLC, as General Partner

By: /s/ R. Daniel Boss
Name: R. Daniel Boss
Title: Senior Vice President – Accounting and Risk Control of the General Partner

By: /s/ Michael W. Hanson
Name: Michael W. Hanson
Title: Vice President and Principal Accounting Officer of the General Partner