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 June 30, 2018

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 2,175,951,128 common units of Enterprise Products Partners L.P. outstanding at the close of business on July 31, 2018. 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)

	June 30, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 57.9	$ 5.1
Restricted cash	283.6	65.2
Accounts receivable – trade, net of allowance for doubtful accounts of $11.8 at June 30, 2018 and $12.1 at December 31, 2017	4,318.3	4,358.4
Accounts receivable – related parties	2.0	1.8
Inventories	1,729.6	1,609.8
Derivative assets	165.1	153.4
Prepaid and other current assets	446.1	312.7
Total current assets	7,002.6	6,506.4
Property, plant and equipment, net	37,054.5	35,620.4
Investments in unconsolidated affiliates	2,581.5	2,659.4
Intangible assets, net of accumulated amortization of $1,651.5 at June 30, 2018 and $1,564.8 at December 31, 2017 (see Note 6)	3,696.1	3,690.3
Goodwill (see Note 6)	5,745.2	5,745.2
Other assets	231.5	196.4
Total assets	$ 56,311.4	$ 54,418.1
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 7)	$ 2,668.7	$ 2,855.0
Accounts payable – trade	893.1	801.7
Accounts payable – related parties	85.6	127.3
Accrued product payables	4,712.6	4,566.3
Accrued interest	372.0	358.0
Derivative liabilities	396.9	168.2
Other current liabilities	320.4	418.6
Total current liabilities	9,449.3	9,295.1
Long-term debt (see Note 7)	23,020.2	21,713.7
Deferred tax liabilities	69.0	58.5
Other long-term liabilities	682.4	578.4
Commitments and contingencies (see Note 16)		
Equity: (see Note 8)		
Partners' equity:		
Limited partners:		
Common units (2,175,951,128 units outstanding at June 30, 2018 and 2,161,089,479 units outstanding at December 31, 2017)	22,794.8	22,718.9
Accumulated other comprehensive loss	(123.2)	(171.7)
Total partners' equity	22,671.6	22,547.2
Noncontrolling interests	418.9	225.2
Total equity	23,090.5	22,772.4
Total liabilities and equity	$ 56,311.4	$ 54,418.1

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues:				
Third parties	$ 8,411.9	$ 6,597.7	$ 17,685.7	$ 13,907.3
Related parties	55.6	9.9	80.3	20.7
Total revenues (see Note 9)	8,467.5	6,607.6	17,766.0	13,928.0
Costs and expenses:				
Operating costs and expenses:				
Third parties	7,174.3	5,457.6	15,078.6	11,539.2
Related parties	377.7	272.6	696.1	524.2
Total operating costs and expenses	7,552.0	5,730.2	15,774.7	12,063.4
General and administrative costs:				
Third parties	20.9	16.0	42.2	36.7
Related parties	30.5	29.7	62.2	59.4
Total general and administrative costs	51.4	45.7	104.4	96.1
Total costs and expenses (see Note 9)	7,603.4	5,775.9	15,879.1	12,159.5
Equity in income of unconsolidated affiliates	122.3	107.0	238.0	201.8
Operating income	986.4	938.7	2,124.9	1,970.3
Other income (expense):				
Interest expense	(274.6)	(245.8)	(526.7)	(495.1)
Change in fair market value of Liquidity Option Agreement (see Note 14)	(8.9)	(18.6)	(16.4)	(24.1)
Gain on step acquisition of unconsolidated affiliate (see Note 11)	2.4	--	39.4	--
Other, net	0.3	0.4	1.0	0.6
Total other expense, net	(280.8)	(264.0)	(502.7)	(518.6)
Income before income taxes	705.6	674.7	1,622.2	1,451.7
Provision for income taxes	(18.4)	(8.7)	(23.5)	(14.7)
Net income	687.2	666.0	1,598.7	1,437.0
Net income attributable to noncontrolling interests	(13.4)	(12.3)	(24.2)	(22.6)
Net income attributable to limited partners	$ 673.8	$ 653.7	$ 1,574.5	$ 1,414.4
Earnings per unit: (see Note 10)				
Basic earnings per unit	$ 0.31	$ 0.30	$ 0.72	$ 0.66
Diluted earnings per unit	$ 0.31	$ 0.30	$ 0.72	$ 0.66

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
Net income	$ 687.2	$ 666.0	$ 1,598.7	$ 1,437.0
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instruments:				
Changes in fair value of cash flow hedges	(13.6)	30.4	(10.2)	175.2
Reclassification of losses (gains) to net income	39.2	(46.0)	24.7	(38.9)
Interest rate derivative instruments:				
Changes in fair value of cash flow hedges	3.5	(6.9)	14.6	(4.5)
Reclassification of losses to net income	9.4	10.0	19.9	19.6
Total cash flow hedges	38.5	(12.5)	49.0	151.4
Other	(0.5)	--	(0.5)	(0.1)
Total other comprehensive income (loss)	38.0	(12.5)	48.5	151.3
Comprehensive income	725.2	653.5	1,647.2	1,588.3
Comprehensive income attributable to noncontrolling interests	(13.4)	(12.3)	(24.2)	(22.6)
Comprehensive income attributable to limited partners	$ 711.8	$ 641.2	$ 1,623.0	$ 1,565.7

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Six Months Ended June 30, 2018	For the Six Months Ended June 30, 2017
Operating activities:		
Net income	$ 1,598.7	$ 1,437.0
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	889.3	808.8
Asset impairment and related charges (see Note 14)	16.8	25.2
Equity in income of unconsolidated affiliates	(238.0)	(201.8)
Distributions received on earnings from unconsolidated affiliates	227.6	205.1
Net gains attributable to asset sales	(1.4)	--
Deferred income tax expense	10.0	0.7
Change in fair market value of derivative instruments	459.0	(43.9)
Change in fair market value of Liquidity Option Agreement	16.4	24.1
Gain on step acquisition of unconsolidated affiliate (see Note 11)	(39.4)	--
Net effect of changes in operating accounts (see Note 17)	(228.5)	82.1
Other operating activities	(12.7)	(2.4)
Net cash flows provided by operating activities	2,697.8	2,334.9
Investing activities:		
Capital expenditures	(1,921.1)	(1,113.1)
Cash used for business combinations, net of cash received (see Note 11)	(149.7)	(191.4)
Investments in unconsolidated affiliates	(45.9)	(24.1)
Distributions received for return of capital from unconsolidated affiliates	25.9	24.8
Proceeds from asset sales	2.6	3.2
Other investing activities	(1.4)	2.0
Cash used in investing activities	(2,089.6)	(1,298.6)
Financing activities:		
Borrowings under debt agreements	38,566.4	33,307.8
Repayments of debt	(37,437.0)	(33,639.3)
Debt issuance costs	(24.3)	--
Cash distributions paid to limited partners (see Note 8)	(1,847.3)	(1,757.8)
Cash payments made in connection with distribution equivalent rights	(8.6)	(7.2)
Cash distributions paid to noncontrolling interests	(28.3)	(23.1)
Cash contributions from noncontrolling interests (see Note 8)	206.9	0.3
Net cash proceeds from the issuance of common units (see Note 8)	261.0	757.2
Other financing activities	(25.8)	(27.8)
Cash used in financing activities	(337.0)	(1,389.9)
Net change in cash and cash equivalents, including restricted cash	271.2	(353.6)
Cash and cash equivalents, including restricted cash, at beginning of period	70.3	417.6
Cash and cash equivalents, including restricted cash, at end of period	$ 341.5	$ 64.0

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, 2018	$ 22,718.9	$ (171.7)	$ 225.2	$ 22,772.4
Net income	1,574.5	--	24.2	1,598.7
Cash distributions paid to limited partners	(1,847.3)	--	--	(1,847.3)
Cash payments made in connection with distribution equivalent rights	(8.6)	--	--	(8.6)
Cash distributions paid to noncontrolling interests	--	--	(28.3)	(28.3)
Cash contributions from noncontrolling interests	--	--	206.9	206.9
Net cash proceeds from the issuance of common units	261.0	--	--	261.0
Common units issued in connection with employee compensation	39.1	--	--	39.1
Common units issued in connection with land acquisition	30.0	--	--	30.0
Amortization of fair value of equity-based awards	52.6	--	--	52.6
Cash flow hedges	--	49.0	--	49.0
Other	(25.4)	(0.5)	(9.1)	(35.0)
Balance, June 30, 2018	$ 22,794.8	$ (123.2)	$ 418.9	$ 23,090.5

	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	1,414.4	--	22.6	1,437.0
Cash distributions paid to limited partners	(1,757.8)	--	--	(1,757.8)
Cash payments made in connection with distribution equivalent rights	(7.2)	--	--	(7.2)
Cash distributions paid to noncontrolling interests	--	--	(23.1)	(23.1)
Cash contributions from noncontrolling interests	--	--	0.3	0.3
Net cash proceeds from the issuance of common units	757.2	--	--	757.2
Common units issued in connection with employee compensation	33.7	--	--	33.7
Amortization of fair value of equity-based awards	49.8	--	--	49.8
Cash flow hedges	--	151.4	--	151.4
Other	(28.3)	(0.1)	1.3	(27.1)
Balance, June 30, 2017	$ 22,788.8	$ (128.7)	$ 220.1	$ 22,880.2

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% of our limited partner interests at June 30, 2018.

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 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.

We conduct substantially all of our business through EPO and are owned 100% by our limited partners from an economic perspective. Enterprise GP manages our partnership and owns a non-economic general partner interest in us. We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates under the collective common control of the DD LLC Trustees and the EPCO Trustees. Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. See Note 15 for information regarding related party matters.

Our results of operations for the six months ended June 30, 2018 are not necessarily indicative of results expected for the full year of 2018. 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 United States ("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, 2017 (the "2017 Form 10-K") filed with the SEC on February 28, 2018.

Note 2. Summary of Significant Accounting Policies

Apart from those matters noted below, there have been no changes in our significant accounting policies since those reported under Note 2 of the 2017 Form 10-K.

Adoption of New Revenue Recognition Policies on January 1, 2018

For periods through December 31, 2017, we accounted for our revenue streams using Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 605, *Revenue Recognition*. Under ASC 605, we recognized revenue when all of the following criteria were met: (i) persuasive evidence of an exchange arrangement existed between us and the counterparty (e.g., published tariffs), (ii) delivery of products or the rendering of services had occurred, (iii) the price of the products or the fee for services was fixed or determinable and (iv) collectibility of the amount owed by the counterparty was reasonably assured.

Effective January 1, 2018, we adopted FASB ASC 606, *Revenue from Contracts with Customers,* using a modified retrospective approach that applied the new revenue recognition standard to existing contracts at the implementation date and any future revenue contracts. As such, our consolidated revenues and related financial information for periods prior to January 1, 2018 were not adjusted and continue to be reported in accordance with ASC 605. We did not record a cumulative effect adjustment upon initially applying ASC 606 since there was no impact on partners' equity upon adoption; however, the extent of our revenue-related disclosures has increased under the new standard.

Due to the large number of individual contracts that were in effect at the implementation date of ASC 606, we evaluated our contracts using a portfolio approach based on the types of products sold or services rendered within our business segments. There are no material differences in the amount or timing of revenues recognized under ASC 606 when compared to ASC 605.

The core principle of ASC 606 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. We apply this core principle by following five key steps outlined in ASC 606: (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 judgment and an analysis of the contract's material terms and conditions.

Substantially all of our revenues are accounted for under ASC 606; however, to a limited extent, some revenues are accounted for under other guidance such as ASC 840, *Leases,* ASC 845, *Nonmonetary Transactions* or ASC 815, *Derivatives and Hedging Activities*.

Under ASC 606, we recognize revenue when or as we satisfy our performance obligation to the customer. In situations where we have recognized revenue, but have a conditional right to consideration (based on something other than the passage of time) from the customer, we recognize unbilled revenue (a contract asset) on our consolidated balance sheet. Unbilled revenue is reclassified to accounts receivable when we have an unconditional right of payment from the customer. Payments received from customers in advance of the period in which we satisfy a performance obligation are recorded as deferred revenue (a contract liability) on our consolidated balance sheet.

Our revenue streams are derived from the sale of products and providing midstream services. Revenues from the sale of products are recognized at a point in time, which represents the transfer of control (and the satisfaction of our performance obligation under the contract) to the customer. From that point forward, the customer is able to direct the use of, and obtain substantially all the benefits from, its use of the products. With respect to midstream services (e.g., interruptible transportation), we satisfy our performance obligations over time and recognize revenues when the services are provided and the customer receives the benefits based on an output measure of volumes redelivered. We believe this measure is a faithful depiction of the transfer of control for midstream services since there is (i) an insignificant period of time between the receipt of customers' volumes and their subsequent redelivery, and (ii) it is not possible to individually track and differentiate customers' inventories as they traverse our facilities. For stand-ready performance obligations (e.g., a storage capacity reservation contract), we recognize revenues over time on a straight-line basis as time elapses over the term of the contract. We believe that these approaches accurately depict the transfer of benefits to the customer.

Customers are invoiced for product purchases or services rendered when we have an unconditional right to consideration under the associated contract. The consideration we are entitled to invoice may be either fixed, variable or a combination of both. Examples of fixed consideration would be fixed payments from customers under take-or-pay arrangements, storage capacity reservation agreements and firm transportation contracts. Variable consideration represents payments from customers that are based on factors that fluctuate (or vary) based on volumes, prices or both. Examples of variable consideration include interruptible transportation agreements, market-indexed product sales contracts and the value of NGLs we retain under natural gas processing agreements. The terms of our billings are typical of the industry for the products we sell.

Under certain midstream service agreements, customers are required to provide a minimum volume over an agreed-upon period with a provision that allows the customer to make-up any volume shortfalls over an agreed-upon period (referred to as shipper "make-up rights"). Revenue pursuant to such agreements is initially deferred and subsequently recognized when either the make-up rights are exercised, the likelihood of the customer exercising the rights becomes remote, or we are otherwise released from the performance obligation.

Customers may contribute funds to us to help offset the construction costs related to pipeline construction activities and production well tie-ins. Under ASC 605, these amounts were accounted for as contributions in aid of construction costs ("CIACs") and netted against property, plant and equipment. Under ASC 606, these receipts are recognized as additional service revenues over the term of the associated midstream services provided to the customer.

As a practical expedient, for those contracts under which we have the ability to invoice the customer in an amount that corresponds directly with the value of the performance obligation completed to date, we recognize revenue as we have the right to invoice.

See Note 9 regarding our new revenue disclosures.

Impact of ASU 2016-18 on Restricted Cash Disclosures

We adopted Accounting Standard Update ("ASU") No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash,* in the fourth quarter of 2017 and applied this ASU retrospectively to the periods presented in our Unaudited Condensed Statements of Consolidated Cash Flows. As a result, the decrease in restricted cash of $319.1 million was excluded from net cash used in investing activities for the six months ended June 30, 2017.

The following table provides a reconciliation of cash and cash equivalents, and restricted cash reported within the Unaudited Condensed Consolidated Balance Sheets that sum to the total of the amounts shown in the Unaudited Condensed Statements of Consolidated Cash Flows.

	June 30, 2018	December 31, 2017
Cash and cash equivalents	$ 57.9	$ 5.1
Restricted cash	283.6	65.2
Total cash, cash equivalents and restricted cash shown in the Unaudited Condensed Statements of Consolidated Cash Flows	$ 341.5	$ 70.3

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. The balance of restricted cash at June 30, 2018 consisted of initial margin requirements of $51.4 million and variation margin requirements of $232.2 million. The initial margin requirements will be returned to us as the related derivative instruments are settled. See Note 14 for information regarding our derivative instruments and hedging activities.

Future Adoption of New Lease Accounting Standard

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 will adopt the new standard on January 1, 2019 and apply it to (i) all new leases entered into after January 1, 2019 and (ii) all existing lease contracts as of January 1, 2019 through a cumulative adjustment to equity. In accordance with this approach, our consolidated operating expenses for periods prior to January 1, 2019 will not be revised.

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 are in the process of reviewing our lease agreements in light of the new guidance. We anticipate that ASC 842 will result in changes to the way our operating leases are recorded, presented and disclosed in our consolidated financial statements.

Our minimum payment obligations under operating leases with terms in excess of one year totaled $430.0 million at June 30, 2018 (undiscounted). Upon adoption, we expect to recognize a ROU asset and a corresponding lease liability based on the present value of such obligations. Based on current estimates, we expect that the total of ROU assets we would recognize under ASC 842 will account for less than 1% of total consolidated assets. Likewise, the corresponding lease liabilities would account for less than 1% of total consolidated liabilities.

Note 3. Inventories

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

	June 30, 2018	December 31, 2017
NGLs	$ 1,120.2	$ 917.4
Petrochemicals and refined products	189.0	161.5
Crude oil	410.0	516.3
Natural gas	10.4	14.6
Total	$ 1,729.6	$ 1,609.8

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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Cost of sales (1)	$ 6,391.9	$ 4,731.1	$ 13,532.3	$ 10,066.8
Lower of cost or net realizable value adjustments recognized within cost of sales	0.7	2.6	2.6	6.0

(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	June 30, 2018	December 31, 2017
Plants, pipelines and facilities (1)	3-45 (5)	$ 41,446.7	$ 37,132.2
Underground and other storage facilities (2)	5-40 (6)	3,508.6	3,460.9
Transportation equipment (3)	3-10	185.6	177.1
Marine vessels (4)	15-30	807.5	803.8
Land		360.3	273.1
Construction in progress		2,345.2	4,698.1
Total		48,653.9	46,545.2
Less accumulated depreciation		11,599.4	10,924.8
Property, plant and equipment, net		$ 37,054.5	$ 35,620.4

(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.

In March 2018, we acquired the remaining 50% member interest of our Delaware Processing joint venture, which resulted in the consolidation of approximately $200 million of property, plant and equipment. See Note 11 for information regarding this recent acquisition.

In April 2018, we acquired 65-acres of waterfront property on the Houston Ship Channel for approximately $85.2 million, all of which was recorded as land. The purchase price consisted of $55.2 million in cash with the balance funded through 1,223,242 newly-issued Enterprise common units. The land is located immediately to the east of our Enterprise Hydrocarbons Terminal ("EHT") and is expected to facilitate future expansion projects at EHT.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Depreciation expense (1)	$ 361.0	$ 321.1	$ 692.8	$ 638.6
Capitalized interest (2)	27.1	44.5	85.3	84.1

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

Asset Retirement Obligations

Property, plant and equipment at June 30, 2018 and December 31, 2017 includes $50.1 million and $39.9 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. The following table presents information regarding our asset retirement obligations, or AROs, since January 1, 2018:

ARO liability balance, January 1, 2018	$ 86.7
Liabilities incurred	0.5
Liabilities settled	(1.5)
Revisions in estimated cash flows	11.7
Accretion expense	2.9
ARO liability balance, June 30, 2018	$ 100.3

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 June 30, 2018	June 30, 2018	December 31, 2017
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 25.0	$ 25.7
K/D/S Promix, L.L.C.	50%	30.9	30.9
Baton Rouge Fractionators LLC	32.2%	16.5	17.0
Skelly-Belvieu Pipeline Company, L.L.C.	50%	36.6	37.0
Texas Express Pipeline LLC	35%	322.3	314.4
Texas Express Gathering LLC	45%	35.4	35.9
Front Range Pipeline LLC	33.3%	163.8	165.7
Delaware Basin Gas Processing LLC	100%	--	107.3
Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC	50%	1,377.6	1,378.9
Eagle Ford Pipeline LLC	50%	388.1	385.2
Eagle Ford Terminals Corpus Christi LLC	50%	100.0	75.1
Natural Gas Pipelines & Services:			
White River Hub, LLC	50%	20.4	20.8
Old Ocean Pipeline, LLC	50%	0.6	--
Petrochemical & Refined Products Services:			
Centennial Pipeline LLC	50%	60.4	60.8
Other	Various	3.9	4.7
Total investments in unconsolidated affiliates		$ 2,581.5	$ 2,659.4

In March 2018, we acquired the remaining 50% membership interest in our Delaware Processing joint venture. See Note 11 for information regarding this recent acquisition.

In May 2018, we and Energy Transfer Partners, L.P. ("Energy Transfer" or "ETP") formed Old Ocean Pipeline, LLC to facilitate the resumption of full service on the Old Ocean natural gas pipeline owned by Energy Transfer. The 24-inch diameter Old Ocean Pipeline originates in Maypearl, Texas in Ellis County and extends south approximately 240 miles to Sweeny, Texas in Brazoria County. Energy Transfer serves as operator of the pipeline.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
NGL Pipelines & Services	$ 39.4	$ 19.0	$ 58.8	$ 34.5
Crude Oil Pipelines & Services	83.5	89.2	181.4	170.4
Natural Gas Pipelines & Services	1.6	0.9	2.6	1.9
Petrochemical & Refined Products Services	(2.2)	(2.1)	(4.8)	(5.0)
Total	$ 122.3	$ 107.0	$ 238.0	$ 201.8

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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Income Statement Data:				
Revenues	$ 461.3	$ 371.9	$ 857.3	$ 715.1
Operating income	288.1	229.8	531.8	433.5
Net income	286.4	237.6	528.7	440.5

Note 6. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	June 30, 2018			December 31, 2017		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 457.3	$ (194.8)	$ 262.5	$ 447.4	$ (187.5)	$ 259.9
Contract-based intangibles	363.4	(227.5)	135.9	280.8	(218.4)	62.4
Segment total	820.7	(422.3)	398.4	728.2	(405.9)	322.3
Crude Oil Pipelines & Services:						
Customer relationship intangibles	2,203.5	(151.0)	2,052.5	2,203.5	(127.0)	2,076.5
Contract-based intangibles	281.0	(193.6)	87.4	281.0	(171.0)	110.0
Segment total	2,484.5	(344.6)	2,139.9	2,484.5	(298.0)	2,186.5
Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,350.3	(432.1)	918.2	1,350.3	(417.1)	933.2
Contract-based intangibles	464.7	(383.8)	80.9	464.7	(379.5)	85.2
Segment total	1,815.0	(815.9)	999.1	1,815.0	(796.6)	1,018.4
Petrochemical & Refined Products Services:						
Customer relationship intangibles	181.4	(48.8)	132.6	181.4	(45.9)	135.5
Contract-based intangibles	46.0	(19.9)	26.1	46.0	(18.4)	27.6
Segment total	227.4	(68.7)	158.7	227.4	(64.3)	163.1
Total intangible assets	$ 5,347.6	$ (1,651.5)	$ 3,696.1	$ 5,255.1	$ (1,564.8)	$ 3,690.3

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
NGL Pipelines & Services	$ 9.3	$ 7.3	$ 16.4	$ 14.6
Crude Oil Pipelines & Services	22.6	22.3	46.6	45.4
Natural Gas Pipelines & Services	9.6	8.8	19.3	17.0
Petrochemical & Refined Products Services	2.1	2.3	4.4	4.7
Total	$ 43.6	$ 40.7	$ 86.7	$ 81.7

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

Remainder of 2018	2019	2020	2021	2022
$ 75.8	$ 151.7	$ 140.7	$ 148.4	$ 144.6

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 2017 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:

	June 30, 2018	December 31, 2017
EPO senior debt obligations:		
Commercial Paper Notes, variable-rates	$ 1,970.0	$ 1,755.7
Senior Notes V, 6.65% fixed-rate, repaid April 2018	--	349.7
Senior Notes OO, 1.65% fixed-rate, repaid May 2018	--	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 TT, 2.80% fixed-rate, due February 2021	750.0	--
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 UU, 4.25% fixed-rate, due February 2048	1,250.0	--
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, repaid April 2018	--	0.3
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	0.4	0.4
Total principal amount of senior debt obligations	22,720.0	21,605.7
EPO Junior Subordinated Notes A, variable-rate, due August 2066 (1)	521.1	521.1
EPO Junior Subordinated Notes C, variable-rate, due June 2067 (2)	256.4	256.4
EPO Junior Subordinated Notes B, fixed/variable-rate, redeemed March 2018	--	682.7
EPO Junior Subordinated Notes D, fixed/variable-rate, due August 2077 (3)	700.0	700.0
EPO Junior Subordinated Notes E, fixed/variable-rate, due August 2077 (4)	1,000.0	1,000.0
EPO Junior Subordinated Notes F, fixed/variable-rate, due February 2078 (5)	700.0	--
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2
Total principal amount of senior and junior debt obligations	25,911.7	24,780.1
Other, non-principal amounts	(222.8)	(211.4)
Less current maturities of debt	(2,668.7)	(2,855.0)
Total long-term debt	$ 23,020.2	$ 21,713.7

(1) Variable rate is reset quarterly and based on 3-month LIBOR plus 3.708%.
(2) Variable rate is reset quarterly and based on 3-month LIBOR plus 2.778%.
(3) Fixed rate of 4.875% through August 15, 2022; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 2.986%.
(4) Fixed rate of 5.250% through August 15, 2027; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 3.033%.
(5) Fixed rate of 5.375% through February 14, 2028; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 2.57%.

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt during the six months ended June 30, 2018:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
Commercial Paper Notes	1.50% to 2.50%	2.14%
Multi-Year Revolving Credit Facility	2.58% to 4.75%	3.31%
EPO Junior Subordinated Notes A	5.08% to 6.07%	5.61%
EPO Junior Subordinated Notes C	4.26% to 5.08%	4.66%

The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at June 30, 2018 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt					
	Total	Remainder of 2018	2019	2020	2021	2022	Thereafter
Commercial Paper Notes	$ 1,970.0	$ 1,970.0	$ --	$ --	$ --	$ --	$ --
Senior Notes	20,750.0	--	1,500.0	1,500.0	1,325.0	650.0	15,775.0
Junior Subordinated Notes	3,191.7	--	--	--	--	--	3,191.7
Total	$ 25,911.7	$ 1,970.0	$ 1,500.0	$ 1,500.0	$ 1,325.0	$ 650.0	$ 18,966.7

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.

Increase in Amount Authorized under Commercial Paper Program

In June 2018, EPO increased the aggregate principal amount of short-term notes that it could issue (and have outstanding at any time) under its commercial paper program from $2.5 billion to $3.0 billion. All commercial paper notes issued under the program are senior unsecured obligations of EPO that are unconditionally guaranteed by Enterprise Products Partners L.P.

Issuance of $2.0 Billion of Senior Notes and $700 Million of Junior Subordinated Notes in February 2018

In February 2018, EPO issued $2.7 billion aggregate principal amount of notes comprised of (i) $750 million principal amount of senior notes due February 15, 2021 (“Senior Notes TT”), (ii) $1.25 billion principal amount of senior notes due February 15, 2048 (“Senior Notes UU”) and (iii) $700 million principal amount of junior subordinated notes due February 15, 2078 (“Junior Subordinated Notes F”).

Net proceeds from these offerings were used by EPO for the temporary repayment of amounts outstanding under its commercial paper program, general company purposes, and the redemption of all $682.7 million outstanding aggregate principal amount of its Junior Subordinated Notes B.

Senior Notes TT were issued at 99.946% of their principal amount and have a fixed-rate interest rate of 2.80% per year. Senior Notes UU were issued at 99.865% of their principal amount and have a fixed-rate interest rate of 4.25% per year. Enterprise Products Partners L.P. has guaranteed the senior notes through an unconditional guarantee on an unsecured and unsubordinated basis.

The Junior Subordinated Notes F are redeemable at EPO’s option, in whole or in part, on one or more occasions, on or after February 15, 2028 at 100% of their principal amount, plus any accrued and unpaid interest thereon, and bear interest at a fixed rate of 5.375% per year through February 14, 2028. Beginning February 15, 2028, the Junior Subordinated Notes F will bear interest at a floating rate based on a three-month LIBOR rate plus 2.57%, reset quarterly. Enterprise Products Partners L.P. has guaranteed the Junior Subordinated Notes F through an unconditional guarantee on an unsecured and subordinated basis.

Redemption of Junior Subordinated Notes B

In March 2018, EPO redeemed all of the $682.7 million outstanding aggregate principal amount of its Junior Subordinated Notes B at a price equal to 100% of the principal amount of the notes being redeemed, plus all accrued and unpaid interest thereon to, but not including, the redemption date.

Lender Financial Covenants
We were in compliance with the financial covenants of our consolidated debt agreements at June 30, 2018.

Letters of Credit
At June 30, 2018, EPO had $86.4 million of letters of credit outstanding primarily related to our commodity hedging activities.

Note 8. Equity and Distributions

Partners' Equity
The following table summarizes changes in the number of our limited partner common units outstanding from January 1, 2018 to June 30, 2018:

Number of common units outstanding at January 1, 2018	2,161,089,479
Common units issued in connection with DRIP and EUPP	9,877,090
Common units issued in connection with the vesting of phantom unit awards	3,285,976
Cancellation of treasury units acquired in connection with the vesting of equity-based awards	(984,605)
Common units issued in connection with employee compensation	1,443,586
Common units issued in connection with land acquisition (see Note 4)	1,223,242
Other	16,360
Number of common units outstanding at June 30, 2018	2,175,951,128

The net cash proceeds we received from the issuance of common units during the six months ended June 30, 2018 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and revolving credit facilities and for general company purposes.

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

Universal shelf registration statement. We have a universal shelf registration statement (the "2016 Shelf") on file with the SEC which 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 $2.7 billion of senior and junior subordinated notes in February 2018 using the 2016 Shelf (see Note 7).

At-the-Market ("ATM") program. We have a registration statement on file with the SEC covering the issuance of up to $2.54 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 six months ended June 30, 2018, we did not issue any common units under the ATM program. During the six months ended June 30, 2017, we issued 20,857,006 common units under this program for aggregate gross cash proceeds of $577.3 million, resulting in total net cash proceeds of $571.8 million.

After taking into account the aggregate sales price of common units sold under the ATM program in periods prior to fiscal 2018, we have the capacity to issue additional common units under the ATM program up to an aggregate sales price of $2.54 billion.

Distribution reinvestment plan. We have a registration statement on file with the SEC in connection with our 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 9,608,839 common units under our DRIP during the six months ended June 30, 2018, which generated net cash proceeds of $253.7 million. Privately held affiliates of EPCO reinvested $100 million through the DRIP during the six months ended June 30, 2018 (this amount being a component of the net cash proceeds presented). During the six months ended June 30, 2017, we issued 6,802,889 common units under our DRIP, which generated net cash proceeds of $178.9 million. After taking into account the number of common units issued under the DRIP through June 30, 2018, we have the capacity to issue an additional 71,108,301 common units under this plan.

Privately held affiliates of EPCO reinvested an additional $106 million through the DRIP in connection with the distribution paid in August 2018.

Employee unit purchase plan. In addition to the DRIP, we have registration statements on file with the SEC in connection with our employee unit purchase plan ("EUPP"). We issued 268,251 common units under our EUPP during the six months ended June 30, 2018, which generated net cash proceeds of $7.3 million. During the six months ended June 30, 2017, we issued 232,792 common units under our EUPP, which generated net cash proceeds of $6.4 million. After taking into account the number of common units issued under the EUPP through June 30, 2018, we may issue an additional 5,492,560 common units under this plan.

Common units issued in connection with employee compensation. In February 2018, the dollar value of discretionary employee bonus payments with respect to the year ended December 31, 2017 (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 1,443,586 common units, which had a value of $39.1 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, 2017.

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, 2018	$ (10.1)	$ (165.1)	$ 3.5	$ (171.7)
Other comprehensive income (loss) before reclassifications	(10.2)	14.6	(0.5)	3.9
Amounts reclassified from accumulated other comprehensive loss	24.7	19.9	--	44.6
Total other comprehensive income (loss)	14.5	34.5	(0.5)	48.5
Balance, June 30, 2018	$ 4.4	$ (130.6)	$ 3.0	$ (123.2)

	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 income (loss) before reclassifications	175.2	(4.5)	(0.1)	170.6
Amounts reclassified from accumulated other comprehensive loss (income)	(38.9)	19.6	--	(19.3)
Total other comprehensive income (loss)	136.3	15.1	(0.1)	151.3
Balance, June 30, 2017	$ 52.5	$ (184.7)	$ 3.5	$ (128.7)

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

		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	Location	2018	2017	2018	2017
Losses (gains) on cash flow hedges:					
Interest rate derivatives	Interest expense	$ 9.4	$ 10.0	$ 19.9	$ 19.6
Commodity derivatives	Revenue	39.4	(46.0)	25.4	(38.5)
Commodity derivatives	Operating costs and expenses	(0.2)	--	(0.7)	(0.4)
Total		$ 48.6	$ (36.0)	$ 44.6	$ (19.3)

For information regarding our interest rate and commodity derivative instruments, see Note 14.

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
2017			
1st Quarter	$ 0.4150	4/28/2017	5/8/2017
2nd Quarter	$ 0.4200	7/31/2017	8/7/2017
2018			
1st Quarter	$ 0.4275	4/30/2018	5/8/2018
2nd Quarter	$ 0.4300	7/31/2018	8/8/2018

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 currently expects to recommend to the Board the following additional quarterly cash distributions through the end of 2018 (with respect to each quarter presented): $0.4325, third quarter of 2018; and $0.4350, fourth quarter of 2018.

Noncontrolling Interests

In June 2018, pursuant to an option agreement, an affiliate of Western Gas Partners, LP ("Western") acquired a noncontrolling 20% equity interest in our subsidiary, Whitethorn Pipeline Company LLC ("Whitethorn"), for approximately $189.6 million in cash. Whitethorn owns the Midland-to-ECHO pipeline, which originates at our Midland, Texas terminal and extends 416 miles to our Sealy, Texas facility. This amount is a component of contributions from noncontrolling interests as presented on our Unaudited Condensed Statement of Consolidated Cash Flows for the six months ended June 30, 2018.

In January 2018, we announced a project to construct, own and operate an ethylene export facility, the location of which was subsequently determined to be at our Morgan's Point facility on the Houston Ship Channel. Navigator Ethylene Terminals LLC holds a noncontrolling 50% equity interest in our consolidated subsidiary, Enterprise Navigator Ethylene Terminal LLC, that owns the export facility, which is expected to be completed in the fourth quarter of 2019.

Other

In May 2018, Apache Corporation ("Apache") executed a long-term supply agreement with us whereby Apache would sell all of its NGL production from the Alpine High discovery to Enterprise. Alpine High is a major hydrocarbon resource located in the Delaware Basin that encompasses rich natural gas (i.e., gas that has a high NGL content), dry natural gas and oil-bearing horizons. In conjunction with the long-term NGL supply agreement, we granted Apache an option to acquire up to a 33% equity interest in our subsidiary that owns the Shin Oak NGL Pipeline, which is currently under construction and expected to be placed into service during the first quarter of 2019. The option is exercisable once the pipeline is placed into commercial service.

Note 9. Revenues

We classify our revenues into sales of products and midstream services. Product sales relate primarily to our various marketing activities whereas midstream services represent our other integrated businesses (i.e., gathering, processing, transportation, fractionation, storage and terminaling). The following table presents our revenues by business segment, and further by revenue type, for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018 (1)	**2017** (2)	**2018** (1)	**2017** (2)
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 2,610.9	$ 2,158.0	$ 5,426.3	$ 5,045.2
Midstream services	662.8	462.6	1,260.7	921.2
Total	3,273.7	2,620.6	6,687.0	5,966.4
Crude Oil Pipelines & Services:				
Sales of crude oil	2,532.2	1,705.1	5,873.9	3,323.7
Midstream services	249.0	194.5	478.2	383.1
Total	2,781.2	1,899.6	6,352.1	3,706.8
Natural Gas Pipelines & Services:				
Sales of natural gas	532.5	560.6	1,092.5	1,104.6
Midstream services	260.3	225.6	505.1	442.8
Total	792.8	786.2	1,597.6	1,547.4
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,413.4	1,114.1	2,702.7	2,325.2
Midstream services	206.4	187.1	426.6	382.2
Total	1,619.8	1,301.2	3,129.3	2,707.4
Total consolidated revenues	$ 8,467.5	$ 6,607.6	$ 17,766.0	$ 13,928.0

(1) Revenues are accounted for under ASC 606 upon implementation at January 1, 2018.
(2) Revenues are accounted for under ASC 605 for historical periods prior to January 1, 2018.

Substantially all of our revenues are derived from contracts with customers as defined within ASC 606. In total, product sales and midstream services accounted for 84% and 16%, respectively, of our consolidated revenues for the three months ended June 30, 2018 and 2017. During the six months ended June 30, 2018 and 2017, product sales and midstream services accounted for 85% and 15%, respectively, of our consolidated revenues.

Apart from the following information regarding natural gas processing, the description of our significant revenue streams by business segment found under Note 3 of the 2017 Form 10-K have not changed in connection with the adoption of ASC 606.

- Natural gas processing utilizes service contracts that are either fee-based, commodity-based or a combination of the two. Our commodity-based contracts include keepwhole, margin-band, percent-of-liquids, percent-of-proceeds and contracts featuring a combination of commodity and fee-based terms. When a cash fee for natural gas processing services is stipulated by a contract, we record revenue as a producer's natural gas has been processed.

  Under ASC 605, our natural gas processing business did not recognize revenue in connection with non-cash consideration (the "equity NGL volumes") it received under percent-of-liquids and similar arrangements. We recognized revenue when the associated NGLs were delivered and sold to downstream customers under NGL marketing product sales contracts.

  Under ASC 606, our natural gas processing business recognizes the value of the equity NGL volumes it receives from customers as a form of midstream service revenue. The value assigned to this non-cash consideration and related inventory is based on the market value of the equity NGLs we are entitled to when the services are performed. We also recognize revenue, along with a corresponding cost of sales, when the NGLs are delivered and sold to downstream customers under NGL marketing product sales contracts.

The additional service revenue recognized for the non-cash consideration increased our total revenues by approximately 2% for the six months ended June 30, 2018 when compared to the amount of revenues we would have recognized under ASC 605 for the quarter. 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.

Unbilled Revenue and Deferred Revenue

The following table provides information regarding our contract assets and contract liabilities as of June 30, 2018:

Contract Asset	Location	Balance
Unbilled revenue (current amount)	Prepaid and other current assets	$ 126.9
Unbilled revenue (noncurrent)	Other assets	--
Total		$ 126.9

Contract Liability	Location	Balance
Deferred revenue (current amount)	Other current liabilities	$ 83.8
Deferred revenue (noncurrent)	Other long-term liabilities	158.4
Total		$ 242.2

The following table presents significant changes in our unbilled revenue and deferred revenue balances during the six months ended June 30, 2018:

	Unbilled Revenue	Deferred Revenue
Balance at January 1, 2018 (upon adoption of ASC 606)	$ --	$ 224.7
Amount included in opening balance transferred to other accounts during period (1)	--	(72.8)
Amount recorded during period	136.4	201.1
Amounts recorded during period transferred to other accounts (1)	(11.7)	(110.8)
Amount recorded in connection with business combination	2.2	--
Balance at June 30, 2018	$ 126.9	$ 242.2

(1) Unbilled revenues are transferred to accounts receivable once we have an unconditional right to consideration from the customer. Deferred revenues are recognized as revenue upon satisfaction of our performance obligation to the customer.

Remaining Performance Obligations

The following table presents estimated fixed consideration from contracts with customers that contain minimum volume commitments, deficiency and similar fees and the term of the contracts exceeds one year. These amounts represent the revenues we expect to recognize in future periods from these contracts as of June 30, 2018. For a significant portion of our revenue, we bill customers a contractual rate for the services provided multiplied by the amount of volume handled in a given period. We have the right to invoice the customer in the amount that corresponds directly with the value of our performance completed to date. Therefore, we are not required to disclose information about the variable consideration of remaining performance obligations as we recognize revenue equal to the amount that we have the right to invoice.

Remainder of 2018	2019	2020	2021	2022	Thereafter	Total
$ 1,643.8	$ 3,168.7	$ 2,796.0	$ 2,253.0	$ 1,792.6	$ 7,584.3	$ 19,238.4

Impact of Change in Accounting Policy – ASC 606 Transition Disclosures
The following information and tables are provided to summarize the material impacts of adopting ASC 606 on our consolidated financial statements for the three and six months ended June 30, 2018.

As noted previously, additional service revenue and related inventory is now recognized in connection with the equity NGL volumes (a form of non-cash consideration) we receive under natural gas processing agreements. When the inventory is sold through our NGL marketing activities, we reflect additional cost of sales amounts within our operating costs and expenses.

Unbilled revenues have historically been presented as a component of accounts receivable on our consolidated balance sheets. Upon implementation of ASC 606, we reclassified these amounts to "Prepaid and other current assets" since these amounts represent conditional rights to consideration. Once we have an unconditional right to consideration, the amount is transferred to accounts receivable.

Historically, amounts received from customers as CIACs related to pipeline construction activities and production well tie-ins have been netted against property, plant and equipment on our consolidated balance sheets and presented as a cash inflow within the investing activities section of our statements of consolidated cash flows. Upon implementation of ASC 606, these amounts are now recognized as a component of midstream service revenue on our statement of operations and are a component of cash provided by operating activities as presented on our statements of consolidated cash flows.

Unaudited Condensed Consolidated Balance Sheet Information as of June 30, 2018

	Impact of change in accounting policy		
	Balances without adoption of ASC 606	Impact of adoption of ASC 606	As Reported
Assets			
Accounts receivable – trade, net	$ 4,445.2	$ (126.9)	$ 4,318.3
Prepaid and other current assets	$ 319.2	$ 126.9	$ 446.1
Property, plant and equipment, net	$ 37,028.3	$ 26.2	$ 37,054.5
Other assets	$ 231.5	$ --	$ 231.5
Liabilities and Equity			
Other long-term liabilities	$ 661.0	$ 21.4	$ 682.4
Partners' equity	$ 22,666.8	$ 4.8	$ 22,671.6

The impact of adoption of ASC 606 was the reclassification of unbilled revenue amounts of $126.9 million from accounts receivable to other current assets.

Unaudited Condensed Consolidated Statement of Operations Information for the Three Months Ended June 30, 2018

	Impact of change in accounting policy		
	Balances without adoption of ASC 606	Impact of adoption of ASC 606	As Reported
Revenues	$ 8,304.1	$ 163.4	$ 8,467.5
Costs and expenses:			
Operating costs and expenses:	$ 7,390.2	$ 161.8	$ 7,552.0

Unaudited Condensed Consolidated Statement of Operations Information for the Six Months Ended June 30, 2018

	Impact of change in accounting policy		
	Balances without adoption of ASC 606	Impact of adoption of ASC 606	As Reported
Revenues	$ 17,485.6	$ 280.4	$ 17,766.0
Costs and expenses:			
Operating costs and expenses:	$ 15,499.1	$ 275.6	$ 15,774.7

The impact of adopting ASC 606 on revenues for the three and six months ended June 30, 2018 includes the recognition of $161.8 million and $275.6 million, respectively, of revenues from non-cash consideration (i.e., equity NGLs) earned when providing natural gas processing services and $1.6 million and $4.8 million, respectively, recognized in connection with CIACs. Operating costs and expenses for the three and six months ended June 30, 2018 includes $161.8 million and $275.6 million, respectively, attributable to cost of sales recognized when the equity NGL products are sold and delivered to customers.

Unaudited Condensed Consolidated Statement of Cash Flows Information for the Six Months Ended June 30, 2018

	Impact of change in accounting policy		
	Balances without adoption of ASC 606	Impact of adoption of ASC 606	As Reported
Operating activities:			
Net income	$ 1,593.9	$ 4.8	$ 1,598.7
Net effect of changes in operating accounts	$ (249.9)	$ 21.4	$ (228.5)
Investing activities:			
Contributions in aid of construction costs	$ 26.2	$ (26.2)	$ --

Note 10. 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% 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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Operating income	$ 986.4	$ 938.7	$ 2,124.9	$ 1,970.3
Adjustments to reconcile operating income to total gross operating margin:				
Add depreciation, amortization and accretion expense in operating costs and expenses	425.3	379.2	819.6	755.4
Add asset impairment and related charges in operating costs and expenses	15.9	14.0	16.8	25.2
Add net losses or subtract net gains attributable to asset sales in operating costs and expenses	(0.9)	0.3	(1.4)	--
Add general and administrative costs	51.4	45.7	104.4	96.1
Adjustments for make-up rights on certain new pipeline projects:				
Add non-refundable payments received from shippers attributable to make-up rights (1)	5.6	8.3	8.3	21.6
Subtract the subsequent recognition of revenues attributable to make-up rights (2)	(22.0)	(6.8)	(36.2)	(15.9)
Total segment gross operating margin	$ 1,461.7	$ 1,379.4	$ 3,036.4	$ 2,852.7

(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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Gross operating margin by segment:				
NGL Pipelines & Services	$ 913.7	$ 759.9	$ 1,798.6	$ 1,615.9
Crude Oil Pipelines & Services	52.8	236.7	272.8	501.3
Natural Gas Pipelines & Services	213.4	194.4	411.3	365.3
Petrochemical & Refined Products Services	281.8	188.4	553.7	370.2
Total segment gross operating margin	$ 1,461.7	$ 1,379.4	$ 3,036.4	$ 2,852.7

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 June 30, 2018	$ 3,268.8	$ 2,733.8	$ 789.5	$ 1,619.8	$ --	$ 8,411.9
Three months ended June 30, 2017	2,617.8	1,895.8	782.9	1,301.2	--	6,597.7
Six months ended June 30, 2018	6,678.4	6,286.5	1,591.5	3,129.3	--	17,685.7
Six months ended June 30, 2017	5,960.8	3,698.4	1,540.7	2,707.4	--	13,907.3
Revenues from related parties:						
Three months ended June 30, 2018	4.9	47.4	3.3	--	--	55.6
Three months ended June 30, 2017	2.8	3.8	3.3	--	--	9.9
Six months ended June 30, 2018	8.6	65.6	6.1	--	--	80.3
Six months ended June 30, 2017	5.6	8.4	6.7	--	--	20.7
Intersegment and intrasegment revenues:						
Three months ended June 30, 2018	6,004.6	9,978.5	165.0	784.0	(16,932.1)	--
Three months ended June 30, 2017	5,642.1	3,383.7	220.6	389.7	(9,636.1)	--
Six months ended June 30, 2018	12,569.5	21,404.8	335.9	1,397.3	(35,707.5)	--
Six months ended June 30, 2017	14,516.9	6,857.7	415.1	804.4	(22,594.1)	--
Total revenues:						
Three months ended June 30, 2018	9,278.3	12,759.7	957.8	2,403.8	(16,932.1)	8,467.5
Three months ended June 30, 2017	8,262.7	5,283.3	1,006.8	1,690.9	(9,636.1)	6,607.6
Six months ended June 30, 2018	19,256.5	27,756.9	1,933.5	4,526.6	(35,707.5)	17,766.0
Six months ended June 30, 2017	20,483.3	10,564.5	1,962.5	3,511.8	(22,594.1)	13,928.0
Equity in income (loss) of unconsolidated affiliates:						
Three months ended June 30, 2018	39.4	83.5	1.6	(2.2)	--	122.3
Three months ended June 30, 2017	19.0	89.2	0.9	(2.1)	--	107.0
Six months ended June 30, 2018	58.8	181.4	2.6	(4.8)	--	238.0
Six months ended June 30, 2017	34.5	170.4	1.9	(5.0)	--	201.8

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 June 30, 2018	$ 14,716.9	$ 5,401.3	$ 8,356.1	$ 6,235.0	$ 2,345.2	$ 37,054.5
At December 31, 2017	13,831.2	5,208.4	8,375.0	3,507.7	4,698.1	35,620.4
Investments in unconsolidated affiliates: (see Note 5)						
At June 30, 2018	630.5	1,865.7	21.0	64.3	--	2,581.5
At December 31, 2017	733.9	1,839.2	20.8	65.5	--	2,659.4
Intangible assets, net: (see Note 6)						
At June 30, 2018	398.4	2,139.9	999.1	158.7	--	3,696.1
At December 31, 2017	322.3	2,186.5	1,018.4	163.1	--	3,690.3
Goodwill: (see Note 6)						
At June 30, 2018	2,651.7	1,841.0	296.3	956.2	--	5,745.2
At December 31, 2017	2,651.7	1,841.0	296.3	956.2	--	5,745.2
Segment assets:						
At June 30, 2018	18,397.5	11,247.9	9,672.5	7,414.2	2,345.2	49,077.3
At December 31, 2017	17,539.1	11,075.1	9,710.5	4,692.5	4,698.1	47,715.3

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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Consolidated revenues:				
NGL Pipelines & Services	$ 3,273.7	$ 2,620.6	$ 6,687.0	$ 5,966.4
Crude Oil Pipelines & Services	2,781.2	1,899.6	6,352.1	3,706.8
Natural Gas Pipelines & Services	792.8	786.2	1,597.6	1,547.4
Petrochemical & Refined Products Services	1,619.8	1,301.2	3,129.3	2,707.4
Total consolidated revenues	$ 8,467.5	$ 6,607.6	$ 17,766.0	$ 13,928.0
Consolidated costs and expenses				
Operating costs and expenses:				
Cost of sales	$ 6,391.9	$ 4,731.1	$ 13,532.3	$ 10,066.8
Other operating costs and expenses (1)	719.8	605.6	1,407.4	1,216.0
Depreciation, amortization and accretion	425.3	379.2	819.6	755.4
Asset impairment and related charges	15.9	14.0	16.8	25.2
Net losses (gains) attributable to asset sales	(0.9)	0.3	(1.4)	--
General and administrative costs	51.4	45.7	104.4	96.1
Total consolidated costs and expenses	$ 7,603.4	$ 5,775.9	$ 15,879.1	$ 12,159.5

(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 11. Business Combinations

On March 29, 2018, we acquired the remaining 50% member interest in our Delaware Processing joint venture for $150.6 million in cash, net of $3.9 million of cash held by the former joint venture. As a result, Delaware Processing is now our wholly-owned consolidated subsidiary. Delaware Processing owns a cryogenic natural gas processing facility having a capacity of 150 million cubic feet per day. The facility is located in Reeves County, Texas and entered service in August 2016. The acquired business serves growing production of NGL-rich natural gas from the Delaware Basin in West Texas and southern New Mexico.

The following table presents the final fair value allocation of assets acquired and liabilities assumed in the acquisition at March 29, 2018.

Purchase price for remaining 50% equity interest in Delaware Processing	$	154.5
Fair value of our 50% equity interest in Delaware Processing held before the acquisition		146.4
Total		300.9
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Assets acquired in business combination:		
Current assets, including cash of $3.9 million	$	10.8
Property, plant and equipment		200.0
Contract-based intangible assets		82.6
Customer relationship intangible assets		9.9
Total assets acquired	$	303.3
Liabilities assumed in business combination:		
Current liabilities	$	(1.8)
Long-term liabilities		(0.6)
Total liabilities assumed	$	(2.4)
Total identifiable net assets	$	300.9
Goodwill	$	--

Prior to this acquisition, we accounted for our investment using the equity method. On a historical pro forma 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 six months ended June 30, 2018 and 2017 would not have differed materially from those we actually reported had the acquisition been completed on January 1, 2017 rather than March 29, 2018.

At March 29, 2018, our 50% equity investment in Delaware Processing was $107.0 million. Upon acquisition of the remaining 50% member interest, our existing equity investment was remeasured to fair value resulting in the recognition of a non-cash $39.4 million gain, which is presented within Other Income on our Unaudited Condensed Consolidated Statement of Operations for the six months ended June 30, 2018.

The results for this business will continue to be reported under the NGL Pipelines & Services business segment.

Note 12. Earnings Per Unit

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
BASIC EARNINGS PER UNIT				
Net income attributable to limited partners	$ 673.8	$ 653.7	$ 1,574.5	$ 1,414.4
Undistributed earnings allocated and cash payments on phantom unit awards (1)	(4.6)	(4.0)	(9.3)	(8.0)
Net income available to common unitholders	$ 669.2	$ 649.7	$ 1,565.2	$ 1,406.4
Basic weighted-average number of common units outstanding	2,174.6	2,144.7	2,170.7	2,135.5
Basic earnings per unit	$ 0.31	$ 0.30	$ 0.72	$ 0.66
DILUTED EARNINGS PER UNIT				
Net income attributable to limited partners	$ 673.8	$ 653.7	$ 1,574.5	$ 1,414.4
Diluted weighted-average number of units outstanding:				
Distribution-bearing common units	2,174.6	2,144.7	2,170.7	2,135.5
Phantom units (1)	10.8	9.6	10.6	9.2
Total	2,185.4	2,154.3	2,181.3	2,144.7
Diluted earnings per unit	$ 0.31	$ 0.30	$ 0.72	$ 0.66

(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 13. Equity-Based Awards

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Equity-classified awards:				
Phantom unit awards	$ 25.9	$ 23.5	$ 50.5	$ 46.3
Restricted common unit awards	--	--	--	0.5
Profits interest awards	1.0	1.6	2.6	3.1
Liability-classified awards	0.1	--	0.2	0.2
Total	$ 27.0	$ 25.1	$ 53.3	$ 50.1

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 June 30, 2018, 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 45,000,000 at June 30, 2018. This amount will automatically increase under the terms of the 2008 Plan by 5,000,000 common units on January 1, 2019 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 June 30, 2018, a total of 18,864,940 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").

Phantom Unit Awards

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

At June 30, 2018, 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, 2018	9,289,501	$ 27.65
Granted (2)	4,967,681	$ 26.81
Vested	(3,285,976)	$ 28.58
Forfeited	(216,897)	$ 26.92
Phantom unit awards at June 30, 2018	10,754,309	$ 26.99

(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 2018 was $133.2 million based on a grant date market price of our common units ranging from $25.40 to $28.18 per unit. An estimated annual forfeiture rate of 3.2% 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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Cash payments made in connection with DERs	$ 4.7	$ 4.0	$ 8.6	$ 7.2
Total intrinsic value of phantom unit awards that vested during period	3.1	3.1	85.1	66.3

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was $158.8 million at June 30, 2018, of which our share of the cost is currently estimated to be $134.2 million. Due to the graded vesting provisions of these awards, we expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.2 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 June 30, 2018:

Employee Partnership	Enterprise Common Units contributed to Employee Partnership by EPCO Holdings	Class A Capital Base (1)	Class A Preference Return (2)	Expected Vesting/ Liquidation Date	Estimated Grant Date Fair Value of Profits Interest Awards (3)	Unrecognized Compensation Cost (4)
PubCo I	2,723,052	$63.7 million	$0.39	Feb. 2020	$13.0 million	$5.9 million
PubCo II	2,834,198	$66.3 million	$0.39	Feb. 2021	$14.7 million	$8.3 million
PubCo III	105,000	$2.5 million	$0.39	Apr. 2020	$0.5 million	$0.3 million
PrivCo I	1,111,438	$26.0 million	$0.39	Feb. 2021	$5.8 million	$0.7 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 irrespective of how such costs will be allocated between us and EPCO and its privately held affiliates.

(4) Represents our expected share of the unrecognized compensation cost at June 30, 2018. 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 1.6 years, 2.6 years, 1.8 years and 2.6 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 2.5%	6.2% to 7.0%	20% to 40%
PubCo II	5.0 years	1.1% to 2.7%	6.1% to 7.0%	27% to 40%
PubCo III	4.0 years	1.0% to 2.2%	6.1% to 6.8%	27% 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.

Note 14. 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.

On January 1, 2018, we early adopted ASU 2017-12, Derivatives and Hedging (Topic 815): *Targeted Improvements to Accounting for Hedging Activities*. Since the impact of the new guidance was not material to our consolidated financial statements, no transition adjustments were recorded. In accordance with ASU 2017-12 both the effective and ineffective portion of a cash flow hedge will be initially reported as a component of accumulated other comprehensive income (loss) and reclassified into earnings when the forecasted transaction affects earnings.

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 forward starting swaps at June 30, 2018:

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Expected Settlement Date	Average Rate Locked	Accounting Treatment
Future long-term debt offering	2 forward starting swaps	$175.0	2/2019	2.56%	Cash flow hedge

As a result of market conditions in January 2018, we elected to terminate $100 million notional amount of the forward starting swaps that were outstanding at December 31, 2017, which resulted in cash proceeds totaling $1.5 million for the first quarter of 2018.

In January 2018, we sold swaptions related to our interest rate hedging activities that resulted in the recognition of $7.2 million of cash gains that were reflected as a reduction in interest expense for the first quarter of 2018. Likewise, in April 2018, we sold swaptions related to our interest rate hedging activities that resulted in the recognition of $11.8 million of cash gains that were reflected as a reduction in interest expense for the second quarter of 2018. The January 2018 swaptions expired in March 2018 and the April 2018 swaptions expired in June 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 June 30, 2018, 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 June 30, 2018 (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 (billion cubic feet ("Bcf"))	16.2	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchase of NGLs (million barrels ("MMBbls"))	0.9	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	0.9	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities (Bcf)	1.8	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	49.9	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	64.1	n/a	Cash flow hedge
NGLs inventory management activities (MMBbls)	0.5	n/a	Fair value hedge
Refined products marketing:			
Forecasted purchase of refined products (MMBbls)	0.9	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.2	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.1	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	9.1	4.1	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	9.9	4.1	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	92.5	2.9	Mark-to-market
Refined products risk management activities (MMBbls) (4)	1.4	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	68.5	29.0	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 2020, November 2018 and December 2020, respectively.
(3) Current and long-term volumes include 45.8 Bcf and 0.8 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.
(4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

The carrying amount of our inventories subject to fair value hedges was $42.8 million and $84.0 million at June 30, 2018 and December 31, 2017, respectively. These amounts, which are presented in "Inventories" on our Unaudited Condensed Consolidated Balance Sheets, are inclusive of cumulative fair value hedging adjustments of $1.4 million and $7.0 million at June 30, 2018 and December 31, 2017, respectively.

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

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

	Asset Derivatives				Liability Derivatives			
	June 30, 2018		December 31, 2017		June 30, 2018		December 31, 2017	
	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	$ 13.0	Current assets	$ --	Current liabilities	$ --	Current liabilities	$ 1.5
Interest rate derivatives	Other assets	--	Other assets	0.1	Other liabilities	--	Other liabilities	0.2
Total interest rate derivatives		13.0		0.1		--		1.7
Commodity derivatives	Current assets	142.7	Current assets	109.5	Current liabilities	141.1	Current liabilities	104.4
Commodity derivatives	Other assets	39.3	Other assets	6.4	Other liabilities	39.2	Other liabilities	6.8
Total commodity derivatives		182.0		115.9		180.3		111.2
Total derivatives designated as hedging instruments		$ 195.0		$ 116.0		$ 180.3		$ 112.9
Derivatives not designated as hedging instruments								
Commodity derivatives	Current assets	$ 9.4	Current assets	$ 43.9	Current liabilities	$ 255.8	Current liabilities	$ 62.3
Commodity derivatives	Other assets	0.2	Other assets	1.9	Other liabilities	23.3	Other liabilities	3.4
Total commodity derivatives		$ 9.6		$ 45.8		$ 279.1		$ 65.7

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 June 30, 2018:							
Interest rate derivatives	$ 13.0	$ --	$ 13.0	$ --	$ --	$ --	$ 13.0
Commodity derivatives	191.6	--	191.6	(185.6)	--	--	6.0
As of December 31, 2017:							
Interest rate derivatives	$ 0.1	$ --	$ 0.1	$ (0.1)	$ --	$ --	$ --
Commodity derivatives	161.7	--	161.7	(157.8)	--	--	3.9

	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 June 30, 2018:							
Commodity derivatives	$ 459.4	$ --	$ 459.4	$ (185.6)	$ --	$ (272.9)	$ 0.9
As of December 31, 2017:							
Interest rate derivatives	$ 1.7	$ --	$ 1.7	$ (0.1)	$ --	$ --	$ 1.6
Commodity derivatives	176.9	--	176.9	(157.8)	--	(17.3)	1.8

Derivative assets and liabilities recorded on our Unaudited Condensed Consolidated Balance Sheets are presented on a gross-basis and determined at the individual transaction level. The tabular presentation above provides a means for comparing the gross amount of derivative assets and liabilities, excluding associated accounts payable and receivable, to the net amount that would likely be receivable or payable under a default scenario based on the existence of rights of offset in the respective derivative agreements. Any cash collateral paid or received is reflected in 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 June 30,		For the Six Months Ended June 30,	
		2018	2017	2018	2017
Interest rate derivatives	Interest expense	$ 0.6	$ 0.4	$ 1.3	$ (0.5)
Commodity derivatives	Revenue	4.8	18.8	4.6	37.6
Total		$ 5.4	$ 19.2	$ 5.9	$ 37.1

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2018	2017	2018	2017
Interest rate derivatives	Interest expense	$ (0.6)	$ (0.3)	$ (1.4)	$ 0.6
Commodity derivatives	Revenue	(4.9)	(16.3)	(1.8)	(28.7)
Total		$ (5.5)	$ (16.6)	$ (3.2)	$ (28.1)

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			
	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Interest rate derivatives	$ 3.5	$ (6.9)	$ 14.6	$ (4.5)
Commodity derivatives – Revenue (1)	(14.2)	31.4	(11.2)	179.0
Commodity derivatives – Operating costs and expenses (1)	0.6	(1.0)	1.0	(3.8)
Total	$ (10.1)	$ 23.5	$ 4.4	$ 170.7

(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			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2018	2017	2018	2017
Interest rate derivatives	Interest expense	$ (9.4)	$ (10.0)	$ (19.9)	$ (19.6)
Commodity derivatives	Revenue	(39.4)	46.0	(25.4)	38.5
Commodity derivatives	Operating costs and expenses	0.2	--	0.7	0.4
Total		$ (48.6)	$ 36.0	$ (44.6)	$ 19.3

Over the next twelve months, we expect to reclassify $37.0 million of losses attributable to interest rate derivative instruments from accumulated other comprehensive loss to earnings as an increase in interest expense. Likewise, we expect to reclassify $4.3 million of net gains attributable to commodity derivative instruments from accumulated other comprehensive income to earnings, $4.4 million as an increase in revenue and $0.1 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 June 30,		For the Six Months Ended June 30,	
		2018	2017	2018	2017
Commodity derivatives	Revenue	$ (406.3)	$ 18.7	$ (559.8)	$ 34.4
Commodity derivatives	Operating costs and expenses	--	(0.8)	(1.5)	3.7
Total		$ (406.3)	$ 17.9	$ (561.3)	$ 38.1

The $561.3 million loss recognized during the 2018 earnings from derivatives not designated as hedging instruments reflects $106.9 million of realized losses on such instruments. It does not reflect the $8.1 million of unrealized losses from fair value hedges. In the aggregate, our unrealized mark-to-market losses for the six months ended June 30, 2018 were $462.5 million inclusive of all derivative instrument types. The following table summarizes the impact of net unrealized, mark-to-market losses on our gross operating margin by segment for the six months ended June 30, 2018:

Unrealized mark-to-market gains (losses) by segment:	
NGL Pipelines & Services	$ 7.8
Crude Oil Pipelines & Services	(467.5)
Natural Gas Pipelines & Services	(2.5)
Petrochemical & Refined Products Services	(0.3)
Total	$ (462.5)

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 are presented before and after the application of Rule 814 of the Chicago Mercantile Exchange ("CME"), which deems that financial instruments cleared by the CME are settled daily in connection with variation margin payments. As a result of this 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. Derivative transactions cleared on exchanges other than the CME (e.g., the Intercontinental Exchange or ICE) continue to be reported on a gross basis.

	June 30, 2018 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	$ --	$ 13.0	$ --	$ 13.0
Commodity derivatives:				
Value before application of CME Rule 814	92.9	224.0	4.8	321.7
Impact of CME Rule 814 change	(6.9)	(123.2)	--	(130.1)
Total commodity derivatives	86.0	100.8	4.8	191.6
Total financial assets	$ 86.0	$ 113.8	$ 4.8	$ 204.6
Financial liabilities:				
Liquidity Option Agreement	$ --	$ --	$ 350.3	$ 350.3
Interest rate derivatives	--	--	--	--
Commodity derivatives:				
Value before application of CME Rule 814	119.5	729.1	3.5	852.1
Impact of CME Rule 814 change	(34.3)	(358.4)	--	(392.7)
Total commodity derivatives	85.2	370.7	3.5	459.4
Total financial liabilities	$ 85.2	$ 370.7	$ 353.8	$ 809.7

	December 31, 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	$ --	$ 0.1	$ --	$ 0.1
Commodity derivatives:				
Value before application of CME Rule 814	47.1	184.9	2.9	234.9
Impact of CME Rule 814 change	(47.1)	(26.1)	--	(73.2)
Total commodity derivatives	--	158.8	2.9	161.7
Total financial assets	$ --	$ 158.9	$ 2.9	$ 161.8
Financial liabilities:				
Liquidity Option Agreement	$ --	$ --	$ 333.9	$ 333.9
Interest rate derivatives	--	1.7	--	1.7
Commodity derivatives:				
Value before application of CME Rule 814	118.4	270.6	1.7	390.7
Impact of CME Rule 814 change	(118.4)	(95.4)	--	(213.8)
Total commodity derivatives	--	175.2	1.7	176.9
Total financial liabilities	$ --	$ 176.9	$ 335.6	$ 512.5

Our Level 3 financial liabilities at June 30, 2018 and December 31, 2017 primarily reflect the fair value assigned to the Liquidity Option Agreement (see Note 16) at each measurement date. The carrying value of the Liquidity Option Agreement (a long-term liability) was $350.3 million and $333.9 million at June 30, 2018 and December 31, 2017, 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 Six Months Ended June 30, 2018	2017
Financial liability balance, net, January 1		$ (332.7)	$ (268.2)
Total gains (losses) included in:			
Net income (1)	Revenue	(0.5)	0.7
Net income	Other expense, net	(7.5)	(5.5)
Other comprehensive income (loss)	Commodity derivative instruments – changes in fair value of cash flow hedges	--	--
Settlements (1)	Revenue	(1.2)	(1.4)
Transfers out of Level 3		--	--
Financial liability balance, net, March 31		(341.9)	(274.4)
Total gains (losses) included in:			
Net income (1)	Revenue	1.3	0.1
Net income	Other expense, net	(8.9)	(18.6)
Other comprehensive income (loss)	Commodity derivative instruments – changes in fair value of cash flow hedges	--	0.1
Settlements (1)	Revenue	0.5	(0.7)
Transfers out of Level 3		--	--
Financial liability balance, net, June 30		$ (349.0)	$ (293.5)

(1) There were unrealized gains of $1.8 million and $0.1 million included in these amounts for the three and six months ended June 30, 2018, respectively. There were unrealized losses of $0.6 million and $1.3 million included in these amounts for the three and six months ended June 30, 2017, respectively.

The following table provides quantitative information regarding our recurring Level 3 fair value measurements for commodity derivatives at June 30, 2018:

	Fair Value Financial Assets	Fair Value Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Crude oil	$ 4.8	$ 3.5	Discounted cash flow	Forward commodity prices	$65.01-$76.84/barrel
Total	$ 4.8	$ 3.5			

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 June 30, 2018. 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 June 30, 2018	2017	For the Six Months Ended June 30, 2018	2017
NGL Pipelines & Services	$ 12.4	$ 2.8	$ 12.4	$ 3.0
Crude Oil Pipelines & Services	0.1	0.6	0.3	0.6
Natural Gas Pipelines & Services	1.8	9.7	2.5	9.9
Petrochemical & Refined Products Services	1.5	--	1.5	--
Total	$ 15.8	$ 13.1	$ 16.7	$ 13.5

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

Total asset impairment and related charges during the six months ended June 30, 2018 and June 30, 2017 include impairment charges attributable to the write-down of spare parts classified as current assets of $0.1 million and $11.7 million, respectively.

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 $23.61 billion and $23.47 billion at June 30, 2018 and December 31, 2017, respectively. The aggregate carrying value of these debt obligations was $23.15 billion and $21.48 billion at June 30, 2018 and December 31, 2017, respectively. These values are based on quoted market prices for such debt or debt of similar terms and maturities (Level 2), our credit standing and the credit standing of our counterparties. Changes in market rates of interest affect the fair value of our fixed-rate debt. The carrying values of our variable-rate long-term debt obligations approximate their fair values since the associated interest rates are market-based. We do not have any long-term investments in debt or equity securities recorded at fair value.

Note 15. Related Party Transactions

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues – related parties:				
Unconsolidated affiliates	$ 55.6	$ 9.9	$ 80.3	$ 20.7
Costs and expenses – related parties:				
EPCO and its privately held affiliates	$ 260.2	$ 247.4	$ 516.9	$ 490.5
Unconsolidated affiliates	148.0	54.9	241.4	93.1
Total	$ 408.2	$ 302.3	$ 758.3	$ 583.6

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

	June 30, 2018	December 31, 2017
Accounts receivable - related parties:		
Unconsolidated affiliates	$ 2.0	$ 1.8
Accounts payable - related parties:		
EPCO and its privately held affiliates	$ 57.0	$ 99.3
Unconsolidated affiliates	28.6	28.0
Total	$ 85.6	$ 127.3

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

Relationship with EPCO and Affiliates
We have an extensive and ongoing relationship with EPCO and its privately held affiliates (including Enterprise GP, our general partner), which are not a part of our consolidated group of companies.

At June 30, 2018, 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
693,530,754	32%

Of the total number of units held by EPCO and its privately held affiliates, 108,222,618 have been pledged as security under the credit facilities of EPCO and its privately held affiliates at June 30, 2018. 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 six months ended June 30, 2018 and 2017, we paid EPCO and its privately held affiliates cash distributions totaling $576.3 million and $553.7 million, respectively.

From time-to-time, EPCO and its privately held affiliates elect to purchase additional common units under our DRIP and ATM program. During the six months ended June 30, 2018, privately held affiliates of EPCO reinvested $100 million through the DRIP. See Note 8 for additional information regarding our DRIP.

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA or by other service providers. The following table presents our related party costs and expenses attributable to the ASA with EPCO for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Operating costs and expenses	$ 228.0	$ 215.9	$ 451.0	$ 427.5
General and administrative expenses	28.4	27.1	57.6	53.9
Total costs and expenses	$ 256.4	$ 243.0	$ 508.6	$ 481.4

Note 16. Commitments and Contingencies

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

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

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

At June 30, 2018 and December 31, 2017, our accruals for litigation contingencies were $4.5 million and 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 ETP signed a non-binding letter of intent in April 2011 that disclaimed any partnership or joint venture related to such project absent executed definitive documents and board approvals of the respective companies. Definitive agreements were never executed and board approval was never obtained for the potential pipeline project. In August 2011, the proposed pipeline project was cancelled due to a lack of customer support.

In September 2011, ETP filed suit against us and a third party in connection with the cancelled project alleging, among other things, that we and ETP had formed a "partnership." The case was tried in the District Court of Dallas County, Texas, 298th Judicial District. While we firmly believe, and argued during our defense, that no agreement was ever executed forming a legal joint venture or partnership between the parties, the jury found that the actions of the two companies, nevertheless, constituted a legal partnership. As a result, the jury found that ETP was wrongfully excluded from a subsequent pipeline project involving a third party, and awarded ETP $319.4 million in actual damages on March 4, 2014. On July 29, 2014, the court entered judgment against us in an aggregate amount of $535.8 million, which 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 court also awarded post-judgment interest on such aggregate amount, to accrue at a rate of 5%, 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 us, rendering judgment that ETP take nothing on those claims, and affirming our counterclaim against ETP of approximately $0.8 million, plus interest.

On August 31, 2017, ETP filed a motion for rehearing before the Dallas Court of Appeals, which was denied on September 13, 2017. On December 27, 2017, ETP filed its Petition for Review with the Supreme Court of Texas and we filed our Response to the Petition for Review on February 26, 2018. On June 8, 2018, the Supreme Court of Texas requested that the parties file briefs on the merits, and the parties are drafting their respective submittals. As of June 30, 2018, 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 $25.8 million and $25.9 million during the three months ended June 30, 2018 and 2017, respectively. For the six months ended June 30, 2018 and 2017, consolidated lease and rental expense was $51.4 million and $52.1 million, respectively. Our operating lease commitments at June 30, 2018 did not differ materially from those reported in our 2017 Form 10-K.

Purchase Obligations. During the first six months of 2018, we entered into long-term product purchase commitments for crude oil with third party suppliers in order to meet future physical delivery obligations on our various systems. On a combined basis, these agreements increased our estimated long-term purchase obligations by approximately $1.2 billion over the next five years and $1.7 billion overall. Apart from these new agreements, there have been no other material changes in our consolidated purchase obligations since those reported in our 2017 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, a German corporation and the ultimate parent company of OTA ("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% 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, currently 54,807,352 units, and assume all future income tax obligations of OTA associated with (i) owning partnership 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 $350.3 million and $333.9 million at June 30, 2018 and December 31, 2017, 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 then held by OTA and reflect any tax planning we believe could be employed. Our valuation estimate for the Liquidity Option at June 30, 2018 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;

- Forecasted annual growth rates of Enterprise's taxable earnings before interest, taxes, depreciation and amortization ranging from 2.1% to 7.2%;

- 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 June 30, 2018, we used ownership interests ranging from 1.8% to 2.5%;

- OTA pays an aggregate federal and state income tax rate of 24% on its taxable income; and

- A discount rate of 8.0% based on our weighted-average cost of capital at June 30, 2018.

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 June 30, 2018, based on these scenarios, we expect that OTA would own approximately 92% 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 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 June 30, 2018 would have increased by $31.1 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.

Note 17. Supplemental Cash Flow Information

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

	For the Six Months Ended June 30,	
	2018	2017
Decrease (increase) in:		
Accounts receivable – trade	$ 18.6	$ 602.7
Accounts receivable – related parties	(0.2)	(1.9)
Inventories	17.6	234.3
Prepaid and other current assets	(82.4)	213.7
Other assets	(11.9)	(64.2)
Increase (decrease) in:		
Accounts payable – trade	112.1	46.6
Accounts payable – related parties	(3.1)	(8.4)
Accrued product payables	30.7	(694.2)
Accrued interest	14.0	(0.8)
Other current liabilities	(306.4)	(252.4)
Other liabilities	(17.5)	6.7
Net effect of changes in operating accounts	$ (228.5)	$ 82.1

We incurred liabilities for construction in progress that had not been paid at June 30, 2018 and December 31, 2017 of $359.0 million and $373.0 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Unaudited Condensed Statements of Consolidated Cash Flows.

Capital expenditures for the six months ended June 30, 2017 reflect the receipt of $29.6 million of CIACs from third parties.

Note 18. 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
June 30, 2018

	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	$ 283.8	$ 81.7	$ (24.0)	$ 341.5	$ --	$ --	$ 341.5
Accounts receivable – trade, net	1,322.5	2,996.5	(0.7)	4,318.3	--	--	4,318.3
Accounts receivable – related parties	92.0	991.0	(1,073.5)	9.5	--	(7.5)	2.0
Inventories	1,270.7	459.5	(0.6)	1,729.6	--	--	1,729.6
Derivative assets	110.6	54.5	--	165.1	--	--	165.1
Prepaid and other current assets	200.2	276.1	(30.8)	445.5	0.5	0.1	446.1
Total current assets	3,279.8	4,859.3	(1,129.6)	7,009.5	0.5	(7.4)	7,002.6
Property, plant and equipment, net	5,955.0	31,098.1	1.4	37,054.5	--	--	37,054.5
Investments in unconsolidated affiliates	42,054.9	4,080.7	(43,554.1)	2,581.5	23,028.0	(23,028.0)	2,581.5
Intangible assets, net	667.1	3,042.6	(13.6)	3,696.1	--	--	3,696.1
Goodwill	459.5	5,285.7	--	5,745.2	--	--	5,745.2
Other assets	292.0	160.7	(222.1)	230.6	0.9	--	231.5
Total assets	$ 52,708.3	$ 48,527.1	$ (44,918.0)	$ 56,317.4	$ 23,029.4	$ (23,035.4)	$ 56,311.4
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 2,668.6	$ 0.1	$ --	$ 2,668.7	$ --	$ --	$ 2,668.7
Accounts payable – trade	355.7	561.4	(24.0)	893.1	--	--	893.1
Accounts payable – related parties	1,083.0	90.0	(1,087.4)	85.6	7.5	(7.5)	85.6
Accrued product payables	2,008.6	2,705.8	(1.8)	4,712.6	--	--	4,712.6
Accrued interest	372.0	0.8	(0.8)	372.0	--	--	372.0
Derivative liabilities	108.3	288.6	--	396.9	--	--	396.9
Other current liabilities	39.7	309.6	(28.9)	320.4	--	--	320.4
Total current liabilities	6,635.9	3,956.3	(1,142.9)	9,449.3	7.5	(7.5)	9,449.3
Long-term debt	23,005.5	14.7	--	23,020.2	--	--	23,020.2
Deferred tax liabilities	10.6	57.0	(0.9)	66.7	--	2.3	69.0
Other long-term liabilities	58.8	495.7	(222.4)	332.1	350.3	--	682.4
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	22,997.5	43,929.6	(43,927.9)	22,999.2	22,671.6	(22,999.2)	22,671.6
Noncontrolling interests	--	73.8	376.1	449.9	--	(31.0)	418.9
Total equity	22,997.5	44,003.4	(43,551.8)	23,449.1	22,671.6	(23,030.2)	23,090.5
Total liabilities and equity	$ 52,708.3	$ 48,527.1	$ (44,918.0)	$ 56,317.4	$ 23,029.4	$ (23,035.4)	$ 56,311.4

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
December 31, 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	$ 65.2	$ 31.5	$ (26.4)	$ 70.3	$ --	$ --	$ 70.3
Accounts receivable – trade, net	1,382.3	2,976.6	(0.5)	4,358.4	--	--	4,358.4
Accounts receivable – related parties	110.3	1,182.1	(1,289.3)	3.1	--	(1.3)	1.8
Inventories	1,038.9	572.3	(1.4)	1,609.8	--	--	1,609.8
Derivative assets	110.0	43.4	--	153.4	--	--	153.4
Prepaid and other current assets	136.3	189.0	(12.6)	312.7	--	--	312.7
Total current assets	2,843.0	4,994.9	(1,330.2)	6,507.7	--	(1.3)	6,506.4
Property, plant and equipment, net	5,622.6	29,996.3	1.5	35,620.4	--	--	35,620.4
Investments in unconsolidated affiliates	41,616.6	4,298.0	(43,255.2)	2,659.4	22,881.5	(22,881.5)	2,659.4
Intangible assets, net	675.5	3,028.6	(13.8)	3,690.3	--	--	3,690.3
Goodwill	459.5	5,285.7	--	5,745.2	--	--	5,745.2
Other assets	296.4	110.0	(211.0)	195.4	1.0	--	196.4
Total assets	$ 51,513.6	$ 47,713.5	$ (44,808.7)	$ 54,418.4	$ 22,882.5	$ (22,882.8)	$ 54,418.1
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 2,854.6	$ 0.4	$ --	$ 2,855.0	$ --	$ --	$ 2,855.0
Accounts payable – trade	290.2	537.8	(26.4)	801.6	0.1	--	801.7
Accounts payable – related parties	1,320.3	112.0	(1,305.0)	127.3	1.3	(1.3)	127.3
Accrued product payables	1,825.9	2,741.7	(1.3)	4,566.3	--	--	4,566.3
Accrued interest	358.0	--	--	358.0	--	--	358.0
Derivative liabilities	115.2	53.0	--	168.2	--	--	168.2
Other current liabilities	108.9	320.1	(10.8)	418.2	--	0.4	418.6
Total current liabilities	6,873.1	3,765.0	(1,343.5)	9,294.6	1.4	(0.9)	9,295.1
Long-term debt	21,699.0	14.7	--	21,713.7	--	--	21,713.7
Deferred tax liabilities	6.7	50.2	(0.5)	56.4	--	2.1	58.5
Other long-term liabilities	60.4	396.5	(212.4)	244.5	333.9	--	578.4
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	22,874.4	43,412.0	(43,433.3)	22,853.1	22,547.2	(22,853.1)	22,547.2
Noncontrolling interests	--	75.1	181.0	256.1	--	(30.9)	225.2
Total equity	22,874.4	43,487.1	(43,252.3)	23,109.2	22,547.2	(22,884.0)	22,772.4
Total liabilities and equity	$ 51,513.6	$ 47,713.5	$ (44,808.7)	$ 54,418.4	$ 22,882.5	$ (22,882.8)	$ 54,418.1

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Three Months Ended June 30, 2018

	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	$ 9,556.8	$ 5,806.4	$ (6,895.7)	$ 8,467.5	$ --	$ --	$ 8,467.5
Costs and expenses:							
Operating costs and expenses	9,256.1	5,191.8	(6,895.9)	7,552.0	--	--	7,552.0
General and administrative costs	8.0	42.0	0.6	50.6	0.8	--	51.4
Total costs and expenses	9,264.1	5,233.8	(6,895.3)	7,602.6	0.8	--	7,603.4
Equity in income of unconsolidated affiliates	667.7	136.5	(681.9)	122.3	683.5	(683.5)	122.3
Operating income	960.4	709.1	(682.3)	987.2	682.7	(683.5)	986.4
Other income (expense):							
Interest expense	(274.8)	(2.6)	2.8	(274.6)	--	--	(274.6)
Other, net	2.4	3.1	(2.8)	2.7	(8.9)	--	(6.2)
Total other expense, net	(272.4)	0.5	--	(271.9)	(8.9)	--	(280.8)
Income before income taxes	688.0	709.6	(682.3)	715.3	673.8	(683.5)	705.6
Provision for income taxes	(6.2)	(12.0)	--	(18.2)	--	(0.2)	(18.4)
Net income	681.8	697.6	(682.3)	697.1	673.8	(683.7)	687.2
Net income attributable to noncontrolling interests	--	(2.0)	(12.7)	(14.7)	--	1.3	(13.4)
Net income attributable to entity	$ 681.8	$ 695.6	$ (695.0)	$ 682.4	$ 673.8	$ (682.4)	$ 673.8

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Three Months Ended June 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	$ 8,541.0	$ 4,274.4	$ (6,207.8)	$ 6,607.6	$ --	$ --	$ 6,607.6
Costs and expenses:							
Operating costs and expenses	8,332.1	3,605.9	(6,207.8)	5,730.2	--	--	5,730.2
General and administrative costs	8.1	36.9	--	45.0	0.7	--	45.7
Total costs and expenses	8,340.2	3,642.8	(6,207.8)	5,775.2	0.7	--	5,775.9
Equity in income of unconsolidated affiliates	716.1	142.3	(751.4)	107.0	673.0	(673.0)	107.0
Operating income	916.9	773.9	(751.4)	939.4	672.3	(673.0)	938.7
Other income (expense):							
Interest expense	(243.8)	(4.3)	2.3	(245.8)	--	--	(245.8)
Other, net	2.3	0.4	(2.3)	0.4	(18.6)	--	(18.2)
Total other expense, net	(241.5)	(3.9)	--	(245.4)	(18.6)	--	(264.0)
Income before income taxes	675.4	770.0	(751.4)	694.0	653.7	(673.0)	674.7
Provision for income taxes	(3.3)	(5.0)	--	(8.3)	--	(0.4)	(8.7)
Net income	672.1	765.0	(751.4)	685.7	653.7	(673.4)	666.0
Net income attributable to noncontrolling interests	--	(1.6)	(12.0)	(13.6)	--	1.3	(12.3)
Net income attributable to entity	$ 672.1	$ 763.4	$ (763.4)	$ 672.1	$ 653.7	$ (672.1)	$ 653.7

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Six Months Ended June 30, 2018

	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	$ 19,874.6	$ 12,215.3	$ (14,323.9)	$ 17,766.0	$ --	$ --	$ 17,766.0
Costs and expenses:							
Operating costs and expenses	19,236.7	10,862.1	(14,324.1)	15,774.7	--	--	15,774.7
General and administrative costs	13.4	88.7	0.6	102.7	1.7	--	104.4
Total costs and expenses	19,250.1	10,950.8	(14,323.5)	15,877.4	1.7	--	15,879.1
Equity in income of unconsolidated affiliates	1,498.7	291.0	(1,551.7)	238.0	1,592.6	(1,592.6)	238.0
Operating income	2,123.2	1,555.5	(1,552.1)	2,126.6	1,590.9	(1,592.6)	2,124.9
Other income (expense):							
Interest expense	(527.0)	(5.1)	5.4	(526.7)	--	--	(526.7)
Other, net	5.2	40.6	(5.4)	40.4	(16.4)	--	24.0
Total other expense, net	(521.8)	35.5	--	(486.3)	(16.4)	--	(502.7)
Income before income taxes	1,601.4	1,591.0	(1,552.1)	1,640.3	1,574.5	(1,592.6)	1,622.2
Provision for income taxes	(11.6)	(11.4)	--	(23.0)	--	(0.5)	(23.5)
Net income	1,589.8	1,579.6	(1,552.1)	1,617.3	1,574.5	(1,593.1)	1,598.7
Net income attributable to noncontrolling interests	--	(3.7)	(23.1)	(26.8)	--	2.6	(24.2)
Net income attributable to entity	$ 1,589.8	$ 1,575.9	$ (1,575.2)	$ 1,590.5	$ 1,574.5	$ (1,590.5)	$ 1,574.5

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Six Months Ended June 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	$ 21,073.8	$ 8,582.6	$ (15,728.4)	$ 13,928.0	$ --	$ --	$ 13,928.0
Costs and expenses:							
Operating costs and expenses	20,571.1	7,220.9	(15,728.6)	12,063.4	--	--	12,063.4
General and administrative costs	15.5	79.6	(0.2)	94.9	1.2	--	96.1
Total costs and expenses	20,586.6	7,300.5	(15,728.8)	12,158.3	1.2	--	12,159.5
Equity in income of unconsolidated affiliates	1,444.9	275.7	(1,518.8)	201.8	1,439.7	(1,439.7)	201.8
Operating income	1,932.1	1,557.8	(1,518.4)	1,971.5	1,438.5	(1,439.7)	1,970.3
Other income (expense):							
Interest expense	(492.6)	(7.0)	4.5	(495.1)	--	--	(495.1)
Other, net	4.5	0.6	(4.5)	0.6	(24.1)	--	(23.5)
Total other expense, net	(488.1)	(6.4)	--	(494.5)	(24.1)	--	(518.6)
Income before income taxes	1,444.0	1,551.4	(1,518.4)	1,477.0	1,414.4	(1,439.7)	1,451.7
Provision for income taxes	(6.2)	(7.6)	--	(13.8)	--	(0.9)	(14.7)
Net income	1,437.8	1,543.8	(1,518.4)	1,463.2	1,414.4	(1,440.6)	1,437.0
Net income attributable to noncontrolling interests	--	(3.3)	(21.9)	(25.2)	--	2.6	(22.6)
Net income attributable to entity	$ 1,437.8	$ 1,540.5	$ (1,540.3)	$ 1,438.0	$ 1,414.4	$ (1,438.0)	$ 1,414.4

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Three Months Ended June 30, 2018

	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	$ 695.2	$ 721.7	$ (681.7)	$ 735.2	$ 711.8	$ (721.8)	$ 725.2
Comprehensive income attributable to noncontrolling interests	--	(2.0)	(12.7)	(14.7)	--	1.3	(13.4)
Comprehensive income attributable to entity	$ 695.2	$ 719.7	$ (694.4)	$ 720.5	$ 711.8	$ (720.5)	$ 711.8

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Three Months Ended June 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	$ 661.3	$ 763.2	$ (751.4)	$ 673.1	$ 641.2	$ (660.8)	$ 653.5
Comprehensive income attributable to noncontrolling interests	--	(1.6)	(12.0)	(13.6)	--	1.3	(12.3)
Comprehensive income attributable to entity	$ 661.3	$ 761.6	$ (763.4)	$ 659.5	$ 641.2	$ (659.5)	$ 641.2

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Six Months Ended June 30, 2018

	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	$ 1,614.1	$ 1,603.2	$ (1,551.5)	$ 1,665.8	$ 1,623.0	$ (1,641.6)	$ 1,647.2
Comprehensive income attributable to noncontrolling interests	--	(3.7)	(23.1)	(26.8)	--	2.6	(24.2)
Comprehensive income attributable to entity	$ 1,614.1	$ 1,599.5	$ (1,574.6)	$ 1,639.0	$ 1,623.0	$ (1,639.0)	$ 1,623.0

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Six Months Ended June 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	$ 1,531.4	$ 1,601.5	$ (1,518.4)	$ 1,614.5	$ 1,565.7	$ (1,591.9)	$ 1,588.3
Comprehensive income attributable to noncontrolling interests	--	(3.3)	(21.9)	(25.2)	--	2.6	(22.6)
Comprehensive income attributable to entity	$ 1,531.4	$ 1,598.2	$ (1,540.3)	$ 1,589.3	$ 1,565.7	$ (1,589.3)	$ 1,565.7

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
For the Six Months Ended June 30, 2018

	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	$ 1,589.8	$ 1,579.6	$ (1,552.1)	$ 1,617.3	$ 1,574.5	$ (1,593.1)	$ 1,598.7
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	144.8	744.7	(0.2)	889.3	--	--	889.3
Equity in income of unconsolidated affiliates	(1,498.7)	(291.0)	1,551.7	(238.0)	(1,592.6)	1,592.6	(238.0)
Distributions received on earnings from unconsolidated affiliates	609.5	136.3	(518.2)	227.6	1,891.4	(1,891.4)	227.6
Net effect of changes in operating accounts and other operating activities	1,390.2	(1,229.3)	3.0	163.9	56.3	--	220.2
Net cash flows provided by operating activities	2,235.6	940.3	(515.8)	2,660.1	1,929.6	(1,891.9)	2,697.8
Investing activities:							
Capital expenditures	(460.7)	(1,405.2)	--	(1,865.9)	(55.2)	--	(1,921.1)
Cash used for business combination, net of cash received	--	(149.7)	--	(149.7)	--	--	(149.7)
Proceeds from asset sales	0.4	2.2	--	2.6	--	--	2.6
Other investing activities	(1,024.5)	160.4	842.7	(21.4)	(253.7)	253.7	(21.4)
Cash used in investing activities	(1,484.8)	(1,392.3)	842.7	(2,034.4)	(308.9)	253.7	(2,089.6)
Financing activities:							
Borrowings under debt agreements	38,566.4	11.6	(11.6)	38,566.4	--	--	38,566.4
Repayments of debt	(37,436.6)	(0.4)	--	(37,437.0)	--	--	(37,437.0)
Cash distributions paid to owners	(1,891.4)	(727.8)	727.8	(1,891.4)	(1,847.3)	1,891.4	(1,847.3)
Cash payments made in connection with DERs	--	--	--	--	(8.6)	--	(8.6)
Cash distributions paid to noncontrolling interests	--	(4.3)	(24.5)	(28.8)	--	0.5	(28.3)
Cash contributions from noncontrolling interests	--	--	206.9	206.9	--	--	206.9
Net cash proceeds from issuance of common units	--	--	--	--	261.0	--	261.0
Cash contributions from owners	253.7	1,223.1	(1,223.1)	253.7	--	(253.7)	--
Other financing activities	(24.3)	--	--	(24.3)	(25.8)	--	(50.1)
Cash provided by (used in) financing activities	(532.2)	502.2	(324.5)	(354.5)	(1,620.7)	1,638.2	(337.0)
Net change in cash and cash equivalents, including restricted cash	218.6	50.2	2.4	271.2	--	--	271.2
Cash and cash equivalents, including restricted cash, at beginning of period	65.2	31.5	(26.4)	70.3	--	--	70.3
Cash and cash equivalents, including restricted cash, at end of period	$ 283.8	$ 81.7	$ (24.0)	$ 341.5	$ --	$ --	$ 341.5

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
For the Six Months Ended June 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	$ 1,437.8	$ 1,543.8	$ (1,518.4)	$ 1,463.2	$ 1,414.4	$ (1,440.6)	$ 1,437.0
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	103.3	705.7	(0.2)	808.8	--	--	808.8
Equity in income of unconsolidated affiliates	(1,444.9)	(275.7)	1,518.8	(201.8)	(1,439.7)	1,439.7	(201.8)
Distributions received on earnings from unconsolidated affiliates	529.3	133.7	(457.9)	205.1	1,753.3	(1,753.3)	205.1
Net effect of changes in operating accounts and other operating activities	1,793.0	(1,766.2)	(0.7)	26.1	59.3	0.4	85.8
Net cash flows provided by operating activities	2,418.5	341.3	(458.4)	2,301.4	1,787.3	(1,753.8)	2,334.9
Investing activities:							
Capital expenditures	(369.3)	(743.8)	--	(1,113.1)	--	--	(1,113.1)
Cash used for business combination, net of cash received	--	(191.4)	--	(191.4)	--	--	(191.4)
Proceeds from asset sales	1.4	1.8	--	3.2	--	--	3.2
Other investing activities	(1,079.2)	(26.4)	1,108.3	2.7	(750.9)	750.9	2.7
Cash used in investing activities	(1,447.1)	(959.8)	1,108.3	(1,298.6)	(750.9)	750.9	(1,298.6)
Financing activities:							
Borrowings under debt agreements	33,307.8	--	--	33,307.8	--	--	33,307.8
Repayments of debt	(33,605.2)	(0.1)	(34.0)	(33,639.3)	--	--	(33,639.3)
Cash distributions paid to owners	(1,753.3)	(491.2)	491.2	(1,753.3)	(1,757.8)	1,753.3	(1,757.8)
Cash payments made in connection with DERs	--	--	--	--	(7.2)	--	(7.2)
Cash distributions paid to noncontrolling interests	--	(4.7)	(18.9)	(23.6)	--	0.5	(23.1)
Cash contributions from noncontrolling interests	--	0.1	0.2	0.3	--	--	0.3
Net cash proceeds from issuance of common units	--	--	--	--	757.2	--	757.2
Cash contributions from owners	750.9	1,088.9	(1,088.9)	750.9	--	(750.9)	--
Other financing activities	0.7	--	--	0.7	(28.5)	--	(27.8)
Cash provided by (used in) financing activities	(1,299.1)	593.0	(650.4)	(1,356.5)	(1,036.3)	1,002.9	(1,389.9)
Net change in cash and cash equivalents, including restricted cash	(327.7)	(25.5)	(0.5)	(353.7)	0.1	--	(353.6)
Cash and cash equivalents, including restricted cash, at beginning of period	366.2	58.9	(7.5)	417.6	--	--	417.6
Cash and cash equivalents, including restricted cash, at end of period	$ 38.5	$ 33.4	$ (8.0)	$ 63.9	$ 0.1	$ --	$ 64.0

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

For the Three and Six Months Ended June 30, 2018 and 2017

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, 2017 (the "2017 Form 10-K"), as filed on February 28, 2018 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% of our limited partner interests at June 30, 2018.

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 second quarter of 2018 compared to the second quarter of 2017. Likewise, the phrase "period-to-period" means the six months ended June 30, 2018 compared to the six months ended June 30, 2017.

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 2017 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% 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. Our business segments are generally organized and managed according to the types of services rendered (or technologies employed) and products produced and/or sold.

Each of our business segments benefits from the supporting role of our related 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, a non-generally accepted accounting principle ("non-GAAP") financial measure, 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.

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

Enterprise to Develop Offshore Texas Crude Oil Export Terminal

In July 2018, management announced that we are in the planning stage to develop a crude oil export terminal located offshore along the Texas Gulf Coast. The terminal would be capable of fully loading Very Large Crude Carrier ("VLCC") marine tankers, which have capacities of approximately 2 MMBbls and provide the most efficient and cost-effective solution to export crude oil to the largest international markets in Asia and Europe. We have started front-end engineering and design work for the terminal and preparing applications for regulatory permitting. Based on initial designs, the project could include approximately 80 miles of 42-inch diameter pipeline extending from onshore facilities to an offshore terminal loading crude oil for export at approximately 85 thousand barrels per hour. A final investment decision for the project will be subject to receiving state and federal permits and customer demand.

Seaway Commences Loading Services for VLCC Tankers

In June 2018, we commenced the loading of VLCC tankers using a combination of our jointly owned Seaway marine terminal located in Texas City, Texas and lightering operations in the Gulf of Mexico. Approximately 1.1 MMBbls of crude oil were loaded onto the FPMC *C Melody* at the Texas City marine terminal and the remainder of the crude oil shipment was loaded on the VLCC in a lightering zone in the Gulf of Mexico. The FPMC *C Melody*, chartered by Vitol, Inc., was the first VLCC to be loaded at a Texas port. The Seaway marine terminal features two docks, a 45-foot draft, an overall length of 1,125 feet, a 220-foot beam (width) and the capacity to load crude oil at a rate of 35 thousand barrels per hour.

In July 2018, we completed a second partial loading of a VLCC tanker at the Seaway terminal. The *Eagle Victoria* loaded approximately 1.1 MMBbls at the terminal, with the balance completed using lightering vessels in the Gulf of Mexico.

Affiliate of Western Gas Acquires 20% Ownership Interest in Midland-to-ECHO Pipeline

In June 2018, pursuant to an option agreement, an affiliate of Western Gas Partners, LP ("Western") acquired a noncontrolling 20% equity interest in our subsidiary, Whitethorn Pipeline Company LLC ("Whitethorn"), for approximately $189.6 million in cash. Whitethorn owns the Midland-to-ECHO Pipeline, which originates at our Midland, Texas terminal and extends 416 miles to our Sealy, Texas facility. Volumes arriving at Sealy are then transported to our ECHO terminal using our Rancho II pipeline, which is a component of our South Texas Crude Oil Pipeline System. Once all infrastructure is complete, the Midland-to-ECHO Pipeline will provide Permian Basin producers with the ability to transport multiple grades of crude oil, including West Texas Intermediate ("WTI"), Light WTI, West Texas Sour and condensate, to Gulf Coast markets. As a result of infrastructure completed in the second quarter of 2018 as well as operating enhancements, the pipeline's transportation capacity is now approximately 575 MBPD. We report the pipeline's transportation volumes on a net basis that reflects our 80% interest.

Upon closing of the transaction whereby Western acquired its 20% equity interest in Whitethorn, we credited Western for 20% of the pipeline's earnings since it was placed into service in November 2017. We paid Western $45.7 million in June 2018 to settle this obligation. In addition to Western's ownership interest in Whitethorn, Western also shares (at a 20% level) in the results of our commercial activities associated with the pipeline.

Apache Dedicates Alpine High NGLs to Enterprise

In May 2018, Apache Corporation ("Apache") executed a long-term supply agreement with us whereby Apache would sell all of its NGL production from the Alpine High discovery to us. Alpine High is a major hydrocarbon resource located in the Delaware Basin that encompasses rich natural gas (i.e., gas that has a high NGL content), dry natural gas and oil-bearing horizons. Apache holds approximately 336,000 net acres in the Alpine High discovery. Enterprise has committed to purchase up to 205 MBPD of NGLs from Apache over the initial ten year term of the supply agreement, the term of which may be extended at the consent of the parties.

In conjunction with the long-term NGL supply agreement, we granted Apache an option to acquire up to a 33% equity interest in our subsidiary that owns the Shin Oak NGL Pipeline, which is currently under construction and expected to be placed into service during the second quarter of 2019. The option is exercisable once the pipeline is placed into commercial service. The Shin Oak NGL Pipeline is designed to transport growing NGL production from the Permian Basin, which includes the Alpine High discovery, 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 550 MBPD.

Construction Begins on Ethylene Export Dock

In May 2018, we announced that construction of our ethylene export terminal located at Morgan's Point on the Houston Ship Channel had commenced. The terminal will have the capacity to export approximately 2.2 billion pounds of ethylene per year. Refrigerated storage for 66 million pounds of ethylene is being constructed on-site and will provide the capability to load ethylene at rates of 2.2 million pounds per hour. The project, which is underwritten by long-term contracts with customers, is expected to be completed in the fourth quarter of 2019.

Enterprise and Energy Transfer form Joint Venture to Restore Service on Old Ocean Pipeline

In May 2018, we announced the formation of a 50/50 joint venture with Energy Transfer Partners, L.P. ("Energy Transfer") to resume full service on the Old Ocean natural gas pipeline owned by Energy Transfer. The 24-inch diameter Old Ocean Pipeline originates in Maypearl, Texas in Ellis County and extends south approximately 240 miles to Sweeny, Texas in Brazoria County. Energy Transfer serves as operator of the pipeline.

The Old Ocean Pipeline resumed limited service in the second quarter of 2018. If fully reconstituted, the Old Ocean Pipeline is expected to provide natural gas transportation capacity of up to 160 MMcf/d by the end of 2018. In addition, both parties are expanding their jointly owned North Texas 36-inch diameter pipeline, which is a component of our Texas Intrastate System, to provide additional natural gas takeaway capacity of 150 MMcf/d from West Texas, including deliveries into the Old Ocean Pipeline. The North Texas Pipeline expansion project is expected to be complete by late fourth quarter of 2018.

The resumption of full service on the Old Ocean Pipeline and expansion of the North Texas Pipeline are expected to provide producers with additional takeaway capacity to accommodate growing natural gas production from the Delaware and Midland Basins.

Expansions of our Front Range and Texas Express Pipelines

In May 2018, we conducted open commitment periods to determine shipper interest in expansions of the Front Range Pipeline ("Front Range") and Texas Express Pipeline ("Texas Express"). Given the positive responses we received from shippers, we will proceed with the proposed expansions. We own a 33.3% equity interest in Front Range and a 35.0% equity interest in Texas Express. We operate both pipelines.

The expansions are designed to facilitate growing production of NGLs from domestic shale basins, including the Denver-Julesburg ("DJ") Basin in Colorado, by providing DJ Basin producers with flow assurance and greater access to the Gulf Coast markets. The expansions are expected to increase the transportation capacity of Front Range and Texas Express by 100 MBPD and 90 MBPD, respectively. We anticipate the expansion projects will be placed into service during the third quarter of 2019.

Enterprise Begins Service at Orla Natural Gas Processing Plant in the Delaware Basin

In May 2018, we announced the start of commercial operations for the initial processing train ("Orla I") at our new cryogenic natural gas processing facility located near Orla, Texas in Reeves County. The Orla I plant has a nameplate natural gas processing capacity of 300 MMcf/d and is capable of extracting in excess of 40 MBPD of NGLs. We expect that the second and third processing trains at the facility ("Orla II" and "Orla III") will be placed into service in the fourth quarter of 2018 and third quarter of 2019, respectively. Once Orla III is completed, the Orla facility is expected to have up to 1 Bcf/d of aggregate natural gas processing capacity and the ability to extract up to 150 MBPD of NGLs. We own and operate the Orla facility.

In conjunction with the start-up of Orla I, we placed into service approximately 70 miles of natural gas pipelines that connect the Orla facility to our Texas Intrastate System. We also placed into service a 30-mile extension of our NGL system that will provide producers at the Orla facility with NGL takeaway capacity and direct access to our integrated network of downstream NGL assets.

Enterprise Expands Marine Terminal on the Houston Ship Channel

In April 2018, we acquired 65-acres of waterfront property on the Houston Ship Channel for approximately $85.2 million, all of which was recorded as land. The purchase price consisted of $55.2 million in cash with the remaining balance funded through 1,223,242 newly-issued Enterprise common units. The land is located immediately to the east of our Enterprise Hydrocarbons Terminal ("EHT") and is expected to facilitate future expansion projects at EHT.

Acquisition of Remaining 50% Ownership Interest in Waha Gas Plant

In March 2018, we acquired the remaining 50% member interest in our Delaware Basin Gas Processing LLC ("Delaware Processing") joint venture for $150.6 million in cash, net of $3.9 million of cash held by the former joint venture. Delaware Processing owns a cryogenic natural gas processing facility (our "Waha" gas plant) having a capacity of 150 MMcf/d. The Waha plant is located in Reeves County, Texas and entered service in August 2016. The acquired business serves growing production of NGL-rich natural gas from the Delaware Basin in West Texas and southern New Mexico. For information regarding this acquisition, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Enterprise to Expand Butane Isomerization Facility

In January 2018, we announced plans to expand our butane isomerization facility by up to 30 MBPD of incremental capacity. This expansion is supported by new long-term agreements, including a 20-year, 35 MBPD fee-based, tolling arrangement, to provide butane isomerization, storage and pipeline services.

Results of Operations

Summarized Consolidated Income Statement Data

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues	$ 8,467.5	$ 6,607.6	$ 17,766.0	$ 13,928.0
Costs and expenses:				
Operating costs and expenses:				
Cost of sales	6,391.9	4,731.1	13,532.3	10,066.8
Other operating costs and expenses	719.8	605.6	1,407.4	1,216.0
Depreciation, amortization and accretion expenses	425.3	379.2	819.6	755.4
Net losses (gains) attributable to asset sales	(0.9)	0.3	(1.4)	--
Asset impairment and related charges	15.9	14.0	16.8	25.2
Total operating costs and expenses	7,552.0	5,730.2	15,774.7	12,063.4
General and administrative costs	51.4	45.7	104.4	96.1
Total costs and expenses	7,603.4	5,775.9	15,879.1	12,159.5
Equity in income of unconsolidated affiliates	122.3	107.0	238.0	201.8
Operating income	986.4	938.7	2,124.9	1,970.3
Interest expense	(274.6)	(245.8)	(526.7)	(495.1)
Change in fair market value of Liquidity Option Agreement	(8.9)	(18.6)	(16.4)	(24.1)
Other, net	2.7	0.4	40.4	0.6
Provision for income taxes	(18.4)	(8.7)	(23.5)	(14.7)
Net income	687.2	666.0	1,598.7	1,437.0
Net income attributable to noncontrolling interests	(13.4)	(12.3)	(24.2)	(22.6)
Net income attributable to limited partners	$ 673.8	$ 653.7	$ 1,574.5	$ 1,414.4

Consolidated Revenues

We classify our revenues into sales of products and midstream services. Product sales relate primarily to our various marketing activities whereas midstream services represent our other integrated businesses (i.e., gathering, processing, transportation, fractionation, storage and terminaling). The following table presents our revenues by business segment, and further by revenue type, for the periods indicated (net of eliminations, dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 2,610.9	$ 2,158.0	$ 5,426.3	$ 5,045.2
Midstream services	662.8	462.6	1,260.7	921.2
Total	3,273.7	2,620.6	6,687.0	5,966.4
Crude Oil Pipelines & Services:				
Sales of crude oil	2,532.2	1,705.1	5,873.9	3,323.7
Midstream services	249.0	194.5	478.2	383.1
Total	2,781.2	1,899.6	6,352.1	3,706.8
Natural Gas Pipelines & Services:				
Sales of natural gas	532.5	560.6	1,092.5	1,104.6
Midstream services	260.3	225.6	505.1	442.8
Total	792.8	786.2	1,597.6	1,547.4
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,413.4	1,114.1	2,702.7	2,325.2
Midstream services	206.4	187.1	426.6	382.2
Total	1,619.8	1,301.2	3,129.3	2,707.4
Total consolidated revenues	$ 8,467.5	$ 6,607.6	$ 17,766.0	$ 13,928.0

For periods through December 31, 2017, we accounted for our revenue streams using Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 605, *Revenue Recognition*. Effective January 1, 2018, we adopted FASB ASC 606, *Revenue from Contracts with Customers,* using a modified retrospective approach that applied the new revenue recognition standard to existing contracts at the implementation date and any future revenue contracts. For information regarding this change in accounting principle (including various transition disclosures), see Notes 2 and 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Selected Energy Commodity Price Data

The following table presents selected average index prices for natural gas 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
	(1)	(2)	(2)	(2)	(2)	(2)	(3)	(3)
2017 by quarter:								
1st Quarter	$3.32	$0.23	$0.71	$0.98	$0.94	$1.10	$0.47	$0.32
2nd Quarter	$3.19	$0.25	$0.63	$0.76	$0.75	$1.07	$0.41	$0.28
3rd Quarter	$2.99	$0.26	$0.77	$0.91	$0.92	$1.10	$0.42	$0.28
4th Quarter	$2.93	$0.25	$0.96	$1.04	$1.04	$1.32	$0.49	$0.35
2017 Averages	$3.11	$0.25	$0.77	$0.92	$0.91	$1.15	$0.45	$0.31
2018 by quarter:								
1st Quarter	$3.01	$0.25	$0.85	$0.96	$1.00	$1.41	$0.53	$0.33
2nd Quarter	$2.80	$0.29	$0.87	$1.00	$1.20	$1.53	$0.52	$0.37
2018 Averages	$2.91	$0.27	$0.86	$0.98	$1.10	$1.47	$0.53	$0.35

(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.

The following table presents selected average index prices for crude oil for the periods indicated:

	WTI Crude Oil, $/barrel	Midland Crude Oil, $/barrel	Houston Crude Oil $/barrel	LLS Crude Oil, $/barrel
	(1)	(2)	(2)	(3)
2017 by quarter:				
1st Quarter	$51.91	$51.72	$53.27	$53.52
2nd Quarter	$48.28	$47.29	$49.77	$50.31
3rd Quarter	$48.20	$47.37	$50.84	$51.62
4th Quarter	$55.40	$55.47	$59.84	$61.07
2017 Averages	$50.95	$50.44	$53.41	$54.13
2018 by quarter:				
1st Quarter	$62.87	$62.51	$65.47	$65.79
2nd Quarter	$67.88	$59.93	$72.38	$72.97
2018 Averages	$65.38	$61.22	$68.93	$69.38

(1) WTI prices are based on commercial index prices at Cushing, Oklahoma as measured by the New York Mercantile Exchange.
(2) Midland and Houston crude oil prices are based on commercial index prices as reported by Argus.
(3) Light Louisiana Sweet ("LLS") prices are based on commercial index prices 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 $0.83 per gallon in the second quarter of 2018 versus $0.60 per gallon during the second quarter of 2017. Likewise, the weighted-average indicative market price for NGLs was $0.80 per gallon during the six months ended June 30, 2018 compared to $0.63 per gallon during the same period in 2017.

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 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for information regarding our commodity hedging activities.

Consolidated Income Statement Highlights

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

Revenues

Second Quarter of 2018 Compared to Second Quarter of 2017. Total revenues for the second quarter of 2018 increased $1.86 billion when compared to the second quarter of 2017 primarily due to a $1.55 billion increase in marketing revenues. Revenues from the marketing of crude oil increased $827.1 million quarter-to-quarter primarily due to higher sales volumes, which accounted for a $455.3 million increase, and higher sales prices, which accounted for an additional $371.8 million increase. Crude oil marketing sales volumes increased quarter-to-quarter and period-to-period as we seek to optimize the utilization of our crude oil pipelines and related assets (e.g., the Midland-to-ECHO Pipeline) and capitalize on pricing opportunities attributable to significant increases in crude oil production in West Texas and the Permian Basin. Revenues from the marketing of NGLs, petrochemicals and refined products increased a net $752.2 million quarter-to-quarter primarily due to higher sales prices, which accounted for an $869.8 million increase, partially offset by a $117.6 million decrease due to lower sales volumes.

Revenues from midstream services for the second quarter of 2018 increased $308.7 million when compared to the second quarter of 2017. As a result of adopting ASC 606, we recognized $161.8 million of revenues during the second quarter of 2018 in connection with the receipt of non-cash consideration (in the form of equity NGLs) for providing natural gas processing services. Midstream service revenues from our pipeline assets increased $92.7 million quarter-to-quarter primarily due to strong demand for transportation services in Texas and on the Appalachia-to-Texas Express ("ATEX") pipeline. Revenues from our terminal and related assets increased $35.6 million quarter-to-quarter, primarily due to higher storage and deficiency fees.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Total revenues for the six months ended June 30, 2018 increased $3.84 billion when compared to the six months ended June 30, 2017 primarily due to a $3.3 billion increase in marketing revenues. Revenues from the marketing of crude oil increased $2.55 billion period-to-period primarily due to higher sales volumes, which accounted for a $1.82 billion increase, and higher sales prices, which accounted for an additional $725.7 million increase. Revenues from the marketing of NGLs, petrochemicals and refined products increased a net $758.6 million period-to-period primarily due to higher sales prices, which accounted for a $1.53 billion increase, partially offset by a $768.9 million decrease due to lower sales volumes.

Revenues from midstream services for the six months ended June 30, 2018 increased $541.3 million when compared to the six months ended June 30, 2017. As a result of adopting ASC 606, we recognized $275.6 million of equity NGL revenues during the six months ended June 30, 2018 for providing natural gas processing services. Midstream service revenues from our pipeline assets increased $194.0 million period-to-period primarily due to strong demand for transportation services in Texas and on the ATEX Pipeline. Revenues from our terminal and related assets increased $57.1 million period-to-period, primarily due to higher storage and deficiency fees. Propylene fractionation revenues increased $17.8 million period-to-period primarily due to higher fees.

Operating costs and expenses

Second Quarter of 2018 Compared to Second Quarter of 2017. Total operating costs and expenses for the second quarter of 2018 increased $1.82 billion when compared to the second quarter of 2017 primarily due to a $1.66 billion increase in cost of sales. The cost of sales associated with our marketing of crude oil increased $1.06 billion quarter-to-quarter primarily due to higher purchase prices, which accounted for a $603.4 million increase, and higher sales volumes, which accounted for an additional $460.3 million increase. The cost of sales associated with our NGL, petrochemical and refined marketing activities increased a net $512.9 million quarter-to-quarter primarily due to higher purchase prices, which accounted for a $792.0 million increase, partially offset by lower sales volumes, which accounted for a $279.1 million decrease. In addition, operating costs and expenses for the second quarter of 2018 includes $161.8 million attributable to cost of sales recognized when equity NGL products are sold and delivered to customers.

Other operating costs and expenses for the second quarter of 2018 increased a net $114.2 million when compared to the second quarter of 2017. Employee compensation, power and maintenance costs increased a combined $63.4 million quarter-to-quarter. Depreciation, amortization and accretion expense increased $46.1 million quarter-to-quarter primarily due to assets we constructed and placed into service since the second quarter of 2017 (e.g., our Midland-to-ECHO Pipeline and propane dehydrogenation ("PDH") facility).

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Total operating costs and expenses for the six months ended June 30, 2018 increased $3.71 billion when compared to the six months ended June 30, 2017 primarily due to a $3.47 billion increase in cost of sales. The cost of sales associated with our marketing of crude oil increased $2.82 billion period-to-period primarily due to higher sales volumes, which accounted for a $1.78 billion increase, and higher purchase prices, which accounted for an additional $1.04 billion increase. The cost of sales associated with our NGL and petrochemical and refined product marketing activities increased a net $467.4 million period-to-period primarily due to higher purchase prices, which accounted for a $1.54 billion increase, partially offset by lower sales volumes, which accounted for a $1.08 billion decrease. In addition, operating costs and expenses for the six months ended June 30, 2018 includes $275.6 million attributable to cost of sales recognized when equity NGL products are sold and delivered to customers.

Other operating costs and expenses for the six months ended June 30, 2018 increased a net $191.4 million when compared to the six months ended June 30, 2017 primarily due to higher employee compensation, power and maintenance costs. In addition, we recorded $33.9 million of expense in 2018 in connection with the earnings allocation arrangement with Western, which ended May 31, 2018, involving our Midland-to-ECHO crude oil pipeline. Depreciation, amortization and accretion expense increased $64.2 million period-to-period primarily due to assets we constructed and placed into service since the second quarter of 2017.

General and administrative costs

General and administrative costs for the three and six months ended June 30, 2018 increased $5.7 million and $8.3 million, respectively, when compared to the same periods in 2017 primarily due to higher costs for employee compensation and legal services.

Equity in income of unconsolidated affiliates

Equity income from our unconsolidated affiliates for the three and six months ended June 30, 2018 increased $15.3 million and $36.2 million, respectively, when compared to the same periods in 2017 primarily due to an increase in earnings from our investments in NGL pipelines.

Operating income

Operating income for the three and six months ended June 30, 2018 increased $47.7 million and $154.6 million, respectively, when compared to the same periods in 2017 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 three and six months ended June 30, 2018 increased $28.8 million and $31.6 million, respectively, when compared to the same periods in 2017. The following table presents the components of our consolidated interest expense for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Interest charged on debt principal outstanding	$ 297.8	$ 272.8	$ 589.8	$ 545.7
Impact of interest rate hedging program, including related amortization (1)	(2.5)	9.3	1.2	18.0
Interest costs capitalized in connection with construction projects (2)	(27.1)	(44.5)	(85.3)	(84.1)
Other (3)	6.4	8.2	21.0	15.5
Total	$ 274.6	$ 245.8	$ 526.7	$ 495.1

(1) Amount presented for three and six months ended June 30, 2018 includes $11.8 million and $19.0 million, respectively, of swaption premium income.

(2) 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.

(3) Primarily reflects facility commitment fees charged in connection with our revolving credit facilities and amortization of debt issuance costs. Amount presented for the six months ended June 30, 2018 includes $7.8 million of debt issuance costs that were written off in March 2018 in connection with the redemption of Junior Subordinated Notes B.

Interest charged on debt principal outstanding, which is the primary driver of interest expense, increased $25.0 million quarter-to-quarter primarily due to increased debt principal amounts outstanding during the second quarter of 2018, which accounted for a $28.4 million increase, partially offset by the effect of lower overall interest rates during the second quarter of 2018, which accounted for a $3.4 million decrease. Our weighted-average debt principal balance for the second quarter of 2018 was $25.97 billion compared to $23.6 billion for the second quarter of 2017.

For the six months ended June 30, 2018, interest charged on debt principal outstanding increased a net $44.1 million period-to-period primarily due to increased debt principal amounts outstanding during the six months ended June 30, 2018, which accounted for a $46.3 million increase, partially offset by the effect of lower overall interest rates during the six months ended June 30, 2018, which accounted for a $2.2 million decrease. Our weighted-average debt principal balance for the six months ended June 30, 2018 was $25.6 billion compared to $23.63 billion for the six months ended June 30, 2017.

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.

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 and six months ended June 30, 2018, expense resulting from changes in fair value of the Liquidity Option Agreement decreased $9.7 million and $7.7 million, respectively, when compared to the same periods in 2017. For information regarding the Liquidity Option Agreement, see Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Gain on step acquisition of unconsolidated affiliate

We recognized gains of $2.4 million and $39.4 million during the three and six months ended June 30, 2018 respectively, related to the step acquisition of Delaware Processing. For information regarding this acquisition, see Note 11 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 six months ended June 30, 2018 increased $9.7 million and $8.8 million, respectively, when compared to the same periods in 2017.

Business Segment Highlights

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, and reflect the periods in which we owned an interest in such operations.

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 June 30,		For the Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
Gross operating margin by segment:				
NGL Pipelines & Services	$ 913.7	$ 759.9	$ 1,798.6	$ 1,615.9
Crude Oil Pipelines & Services	52.8	236.7	272.8	501.3
Natural Gas Pipelines & Services	213.4	194.4	411.3	365.3
Petrochemical & Refined Products Services	281.8	188.4	553.7	370.2
Total segment gross operating margin (1)	1,461.7	1,379.4	3,036.4	2,852.7
Net adjustment for shipper make-up rights	16.4	(1.5)	27.9	(5.7)
Total gross operating margin (non-GAAP)	$ 1,478.1	$ 1,377.9	$ 3,064.3	$ 2,847.0

(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 10 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% 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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Operating income (GAAP)	$ 986.4	$ 938.7	$ 2,124.9	$ 1,970.3
Adjustments to reconcile operating income to total gross operating margin:				
Add depreciation, amortization and accretion expense in operating costs and expenses	425.3	379.2	819.6	755.4
Add asset impairment and related charges in operating costs and expenses	15.9	14.0	16.8	25.2
Subtract net gains or add net losses attributable to asset sales in operating costs and expenses	(0.9)	0.3	(1.4)	--
Add general and administrative costs	51.4	45.7	104.4	96.1
Total gross operating margin (non-GAAP)	$ 1,478.1	$ 1,377.9	$ 3,064.3	$ 2,847.0

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.

NGL Pipelines & Services

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Segment gross operating margin:				
Natural gas processing and related NGL marketing activities	$ 309.7	$ 204.7	$ 558.2	$ 482.6
NGL pipelines, storage and terminals	465.4	436.3	974.7	891.2
NGL fractionation	138.6	118.9	265.7	242.1
Total	$ 913.7	$ 759.9	$ 1,798.6	$ 1,615.9
Selected volumetric data:				
Equity NGL production (MBPD) (1)	164	164	164	157
Fee-based natural gas processing (MMcf/d) (2)	4,624	4,660	4,554	4,598
NGL pipeline transportation volumes (MBPD)	3,408	3,083	3,347	3,160
NGL marine terminal volumes (MBPD)	597	474	586	521
NGL fractionation volumes (MBPD)	927	841	907	820

(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

Second Quarter of 2018 Compared to Second Quarter of 2017. Gross operating margin from natural gas processing and related NGL marketing activities for the second quarter of 2018 increased $105.0 million when compared to the second quarter of 2017.

Gross operating margin from our Meeker, Pioneer and Chaco natural gas processing plants increased $51.8 million quarter-to-quarter primarily due to higher average processing margins (including the impact of hedging activities). On a combined basis for these plants, fee-based natural gas processing volumes increased 147 MMcf/d. Likewise, gross operating margin from our South Texas natural gas processing plants increased $13.5 million quarter-to-quarter primarily due to higher average processing margins (including the impact of hedging activities). Fee-based natural gas processing volumes attributable to our South Texas plants decreased 97 MMcf/d.

Gross operating margin from our Permian Basin natural gas processing plants (South Eddy, Orla and Waha) increased $12.4 million quarter-to-quarter. Gross operating margin from our Waha gas plant increased $6.4 million quarter-to-quarter and fee-based natural gas processing volumes increased 66 MMcf/d quarter-to-quarter primarily due to our acquisition of the remaining 50% equity interest in the Delaware Basin facility in March 2018. In addition, during the second quarter of 2018, we commenced initial operations at our Orla gas plant, which contributed gross operating margin of $4.7 million and fee-based natural gas processing volumes of 122 MMcf/d for the period. Gross operating margin from our South Eddy gas plant increased $1.6 million quarter-to-quarter primarily due to higher average processing fees, which accounted for a $10.0 million increase, partially offset by lower natural gas processing volumes of 135 MMcf/d, which accounted for an $8.7 million decrease.

Gross operating margin from our natural gas processing plants in Louisiana and Mississippi increased $3.4 million quarter-to-quarter primarily due to higher average processing margins. Fee-based natural gas processing volumes for these plants decreased 153 MMcf/d quarter-to-quarter.

Gross operating margin from our NGL marketing activities increased a net $24.1 million quarter-to-quarter primarily due to higher average sales margins, which accounted for a $92.5 million increase, partially offset by a $69.5 million decrease due to lower sales volumes. The results from marketing strategies that optimize our transportation and plant assets increased a combined $39.6 million quarter-to-quarter, partially offset by a $19.4 million decrease in earnings from the optimization of our storage assets.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Gross operating margin from natural gas processing and related NGL marketing activities for the six months ended June 30, 2018 increased a net $75.6 million when compared to the six months ended June 30, 2017.

Gross operating margin from our Meeker, Pioneer and Chaco natural gas processing plants increased $74.7 million period-to-period primarily due to higher average processing margins (including the impact of hedging activities). On a combined basis for these plants, fee-based natural gas processing volumes and equity NGL production increased 94 MMcf/d and 7 MBPD, respectively, period-to-period. Gross operating margin from our South Texas natural gas processing plants increased $23.0 million period-to-period primarily due to higher average processing margins (including the impact of hedging activities). Fee-based natural gas processing volumes for these plants decreased 117 MMcf/d.

Gross operating margin from our natural gas processing plants in the Permian Basin increased $17.4 million period-to-period. Gross operating margin from our Waha gas plant increased $9.5 million period-to-period and fee-based natural gas processing volumes increased 51 MMcf/d period-to-period primarily due to our acquisition of the remaining 50% equity interest in the facility in March 2018. In addition, our newly commissioned Orla gas plant contributed $3.9 million of gross operating margin and 122 MMcf/d of fee-based processing volumes for the six months ended June 30, 2018. Gross operating margin from our South Eddy gas plant increased a net $4.3 million period-to-period primarily due to higher average processing fees, which accounted for a $4.9 million increase, and higher average processing margins, which accounted for an additional $2.1 million increase, partially offset by lower processing volumes of 30 MMcf/d, which accounted for a $2.3 million decrease.

Gross operating margin from our natural gas processing plants in Louisiana and Mississippi decreased $2.5 million period-to-period primarily due to a 170 MMcf/d decrease in processing volumes.

Gross operating margin from our NGL marketing activities decreased a net $38.8 million period-to-period primarily due to lower sales volumes, which accounted for a $169.6 million decrease, partially offset by a $129.7 million increase due to higher sales margins. The results from marketing strategies that optimize our storage and marine terminal assets decreased a combined $95.6 million period-to-period, partially offset by a $48.0 million increase in earnings from the optimization of our transportation assets.

<u>*NGL pipelines, storage and terminals*</u>

Second Quarter of 2018 Compared to Second Quarter of 2017. Gross operating margin from NGL pipelines, storage and terminal assets for the second quarter of 2018 increased a net $29.1 million when compared to the second quarter of 2017.

Gross operating margin from our Seminole, Chaparral and affiliated pipelines increased a combined $24.6 million quarter-to-quarter primarily due to higher average transportation fees, which accounted for a $15.5 million increase, and higher transportation volumes, which accounted for an additional $11.9 million increase, partially offset by an increase in maintenance costs of $2.8 million. On a combined basis, NGL transportation volumes on these pipelines increased 120 MBPD quarter-to-quarter.

Gross operating margin from ATEX increased $12.9 million quarter-to-quarter primarily due to higher transportation volumes, which increased 38 MBPD quarter-to-quarter. Gross operating margin from our Dixie Pipeline and related terminals decreased a combined $11.8 million quarter-to-quarter primarily due to higher maintenance and other operating costs, which accounted for an $8.3 million decrease, lower storage fee revenues, which accounted for a $1.6 million decrease, and lower transportation volumes of 11 MBPD, which accounted for a $1.2 million decrease.

Gross operating margin from our Mid-America Pipeline System and related terminals decreased $11.6 million quarter-to-quarter primarily due to lower average transportation fees. Transportation volumes along our Mid-America Pipeline increased 33 MBPD quarter-to-quarter.

Gross operating margin from our Morgan's Point Ethane Export Terminal increased $15.7 million quarter-to-quarter primarily due to a 102 MBPD increase in loading volumes to 169 MBPD for the second quarter of 2018. Gross operating margin from the related Channel Pipeline increased $3.1 million quarter-to-quarter primarily due to a 104 MBPD increase in ethane transportation volumes to our Morgan's Point facility.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Gross operating margin from NGL pipelines, storage and terminal assets for the six months ended June 30, 2018 increased a net $83.5 million when compared to the six months ended June 30, 2017.

Gross operating margin from our Seminole, Chaparral and affiliated pipelines increased a net $47.0 million period-to-period primarily due to higher average transportation fees, which accounted for a $28.2 million increase, and higher transportation volumes, which accounted for an additional $22.0 million increase, partially offset by increased maintenance costs, which accounted for a $3.3 million decrease. On a combined basis, NGL transportation volumes on these pipelines increased 94 MBPD period-to-period.

Gross operating margin from ATEX increased $31.5 million period-to-period primarily due to higher transportation volumes, which increased 35 MBPD period-to-period.

Gross operating margin from our Morgan's Point Ethane Export Terminal increased $27.6 million period-to-period primarily due to higher ethane loading volumes of 89 MBPD. Likewise, gross operating margin from our Channel Pipeline increased $1.7 million period-to-period primarily due to higher ethane transportation volumes to our Morgan's Point facility of 89 MBPD. Gross operating margin from EHT decreased $11.5 million period-to-period primarily due to a 23 MBPD decrease in LPG volumes, which accounted for a $6.3 million decrease, and higher maintenance and other operating costs, which accounted for an additional $3.6 decrease.

Gross operating margin from our storage facilities in South Louisiana and Mont Belvieu increased a combined $13.4 million period-to-period primarily due to increased storage activity.

Gross operating margin from our South Texas NGL Pipeline System decreased $11.5 million period-to-period primarily due to lower transportation volumes, which accounted for a $6.8 million decrease, lower average transportation fees, which accounted for a $3.5 million decrease, and lower storage revenues, which accounted for an additional $1.2 million decrease. Transportation volumes for the South Texas NGL Pipeline System decreased 23 MBPD period-to-period.

Gross operating margin from our Dixie Pipeline and related terminals decreased a combined $10.3 million period-to-period primarily due to higher maintenance and other operating costs. Gross operating margin from our Mid-America Pipeline System and related terminals decreased $10.1 million period-to-period primarily due to lower average transportation fees. Transportation volumes along our Mid-America Pipeline increased 24 MBPD period-to-period.

NGL fractionation
Second Quarter of 2018 Compared to Second Quarter of 2017. Gross operating margin from NGL fractionation for the second quarter of 2018 increased $19.7 million when compared to the second quarter of 2017. Gross operating margin from our Mont Belvieu NGL fractionators increased $8.9 million quarter-to-quarter primarily due to higher fractionation volumes of 83 MBPD (net to our interest) resulting from our ninth NGL fractionator being placed into service in May 2018. Gross operating margin from our Hobbs NGL fractionator increased $7.4 million quarter-to-quarter primarily due to higher product blending revenues, which accounted for a $3.6 million increase, and lower maintenance and other operating costs, which accounted for an additional $2.7 million increase.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Gross operating margin from NGL fractionation for the six months ended June 30, 2018 increased $23.6 million when compared to the six months ended June 30, 2017. Gross operating margin from our Mont Belvieu NGL fractionators increased $11.7 million period-to-period primarily due to higher fractionation volumes of 85 MBPD (net to our interest) resulting from the start-up of our ninth NGL fractionator. Gross operating margin from our Hobbs NGL fractionator increased $11.1 million period-to-period primarily due to higher product blending revenues, which accounted for a $5.8 million increase, and lower maintenance and other operating costs, which accounted for an additional $3.1 million increase.

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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Segment gross operating margin:				
Midland-to-ECHO Pipeline and related marketing activities, excluding associated non-cash mark-to-market losses	$ 98.5	$ --	$ 147.9	$ --
Mark-to-market losses attributable to the Midland-to-ECHO Pipeline	(309.9)	--	(423.9)	
Total Midland-to-ECHO Pipeline and related marketing activities	$ (211.4)	$ --	$ (276.0)	$ --
Other crude oil pipelines, terminals and marketing results	264.2	236.7	548.8	501.3
Total	$ 52.8	$ 236.7	$ 272.8	$ 501.3
Selected volumetric data:				
Crude oil pipeline transportation volumes (MBPD)	2,050	1,475	2,041	1,416
Crude oil marine terminal volumes (MBPD)	802	488	718	482

Midland-to-ECHO Pipeline and related marketing activities
Gross operating margin from our Midland-to-ECHO Pipeline and related marketing activities was a combined loss of $211.4 million for the second quarter of 2018. Likewise, we recorded a $276.0 million combined loss from this business with respect to the six months ended June 30, 2018. Transportation volumes for the Midland-to-ECHO Pipeline, which entered limited commercial service in November 2017 and full service in April 2018, averaged 436 MBPD and 417 MBPD during the three and six months ended June 30, 2018, respectively (net to our interest).

Gross operating margin for this business for the three and six months ended June 30, 2018 includes non-cash mark-to-market losses of $309.9 million and $423.9 million, respectively, associated with the hedging of crude oil commodity price differentials (basis spreads) between the Midland and Houston area markets. These hedges, which were entered into throughout 2017, served to lock in an average $2.62 per barrel positive margin on our anticipated purchases of crude oil at Midland and subsequent anticipated sales to customers in the Houston area for periods extending predominantly into 2019 and minimally in 2020. The mark-to-market losses recognized during the three and six months ended June 30, 2018 were due to the widening of the basis spreads between Midland and Houston to an average of $14.83 per barrel through 2020 (as of June 30, 2018).

Basis swaps, in all but very limited circumstances, do not qualify for cash flow hedge accounting despite being highly effective at hedging the price risk inherent in the underlying physical transactions. The volume hedged throughout the remainder of 2018 through 2020 varies from quarter-to-quarter and year-to-year, however the hedge levels generally correspond to pipeline capacity currently expected to be available to us during the first three years of the pipeline's operations as customer commitment volumes ramp up to peak levels.

If the basis spreads underlying these hedges widen further, we would be exposed to additional temporary non-cash mark-to-market losses. Conversely, if basis spreads narrow in the future reverting back towards or below the average $2.62 per barrel spread we originally locked in, then we would recognize temporary non-cash mark-to-market gains in future periods. When the forecasted physical receipts and deliveries of crude oil ultimately occur in the future, we will realize a physical gross margin at then prevailing commodity price spreads; however the realized settlement of the associated financial hedges should convert that physical margin to the average $2.62 per barrel spread of the financial hedges. At that time, the unrealized mark-to-market losses recognized in the three and six months ended June 30, 2018 and in future periods until the physical deliveries occur will be reversed, thus eliminating their impact to cumulative earnings recognized over the entire life-to-date period of the hedge.

The basis spread between the Midland and Houston markets continues to fluctuate. We also have uncommitted capacity on the pipeline that could provide us with potential upside to widening or downside to narrowing market spreads. For information regarding the impact of these spreads on our crude oil marketing hedging portfolio, see Item 3, Quantitative and Qualitative Disclosures about Market Risk, within this Part I, Item 2. For general information regarding our derivative instruments and hedging activities, see Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Gross operating margin from the Midland-to-ECHO Pipeline for the three and six months ended June 30, 2018 was also reduced by $9.8 million and $33.9 million, respectively, in connection with the allocation of pipeline earnings to Western upon closing of their acquisition of a noncontrolling 20% equity interest in the pipeline on June 1, 2018. For additional information regarding this transaction, see "Significant Recent Developments" within this Part I, Item 2.

Other crude oil pipelines, terminals and marketing results
Second Quarter of 2018 Compared to Second Quarter of 2017. Gross operating margin from our other crude oil pipelines, terminals and related marketing activities for the second quarter of 2018 increased $27.5 million when compared to the second quarter of 2017.

Gross operating margin from our South Texas Crude Oil Pipeline System increased a net $21.5 million quarter-to-quarter primarily due to higher transportation volumes, which accounted for $11.1 million of the increase, and higher firm capacity reservation fees associated with the Midland-to-ECHO Pipeline, which accounted for an additional $12.1 million of the increase, partially offset by lower average transportation fees, which accounted for a $9.2 million decrease. Crude oil transportation volumes for this system increased 34 MBPD quarter-to-quarter.

Gross operating margin from crude oil export activities at EHT increased $14.3 million quarter-to-quarter primarily due to higher loading volumes, which increased 203 MBPD. Gross operating margin from our Midland, Texas and ECHO terminals increased a combined $12.3 million quarter-to-quarter primarily due to higher throughput and storage volumes attributable to movements on the Midland-to-ECHO Pipeline.

Gross operating margin from our EFS Midstream System increased $5.8 million quarter-to-quarter primarily due to increased deficiency fee revenues, which accounted for a $3.8 million increase, and lower maintenance and other operating costs, which accounted for an additional $1.9 million increase.

Gross operating margin from our equity investment in the Eagle Ford Crude Oil Pipeline System increased $3.8 million quarter-to-quarter primarily due to higher transportation volumes, which increased 70 MBPD (net to our interest) when compared to the second quarter of 2017.

Gross operating margin from our crude oil marketing activities, excluding those attributable to our commercial activities on the Midland-to-ECHO Pipeline, decreased $25.6 million quarter-to-quarter primarily due to non-cash mark-to-market losses of $28.1 million in the second quarter of 2018 compared to non-cash mark-to-market gains of $14.9 million in the second quarter of 2017. The mark-to-market losses recognized by this business in the second quarter of 2018 are related to the widening of crude oil commodity prices differentials between the Midland, Texas and Cushing, Oklahoma markets.

Gross operating margin from our equity investment in the Seaway Pipeline decreased $7.2 million quarter-to-quarter primarily due to a decrease in long-haul transportation revenues attributable to an increase in walk-up shipper volumes, which are charged a lower tariff. Overall, transportation volumes on the Seaway Pipeline increased 47 MBPD quarter-to-quarter (net to our interest). Crude oil exports from Seaway's dock facilities increased 76 MBPD quarter-to-quarter (net to our interest), which includes the loading of a VLCC tanker at Seaway's Texas City terminal in June 2018. See "Significant Recent Developments" within this Part I, Item 2 for information regarding our recent operations and projects involving VLCC ships.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Gross operating margin from our other crude oil pipelines, terminals and related marketing activities for the six months ended June 30, 2018 increased $47.5 million when compared to the six months ended June 30, 2017.

Gross operating margin from our South Texas Crude Oil Pipeline System increased a net $61.2 million period-to-period primarily due to higher firm capacity reservation fees associated with the Midland-to-ECHO Pipeline, which accounted for $36.1 million of the increase, and higher transportation volumes, which accounted for an additional $32.7 million increase, partially offset by lower average transportation fees, which accounted for a $16.2 million decrease.

Gross operating margin from crude oil export activities at EHT increased $22.4 million period-to-period primarily due to higher loading volumes, which increased 192 MBPD. Gross operating margin from our Midland, Texas and ECHO terminals increased a combined $22.0 million period-to-period primarily due to higher throughput and storage volumes attributable to movements on the Midland-to-ECHO Pipeline.

Gross operating margin from our EFS Midstream System increased $10.7 million period-to-period primarily due to increased deficiency fee revenues, which accounted for a $5.1 million increase, and lower operating costs, which accounted for an additional $2.2 million increase.

Gross operating margin from our equity investment in the Eagle Ford Crude Oil Pipeline System increased $7.9 million period-to-period primarily due to higher transportation volumes, which increased 80 MBPD (net to our interest) when compared to the same period in 2017.

Gross operating margin from our crude oil marketing activities, excluding those attributable to our commercial activities on the Midland-to-ECHO Pipeline, decreased $67.2 million period-to-period primarily due to non-cash mark-to-market losses of $43.6 million for the six months ended June 30, 2018 compared to non-cash mark-to-market gains of $34.7 million for the same period in 2017. As noted previously, the mark-to-market losses recognized by this business in 2018 are related to the widening of crude oil commodity prices differentials between the Midland, Texas and Cushing, Oklahoma markets.

Gross operating margin from our equity investment in the Seaway Pipeline decreased a net $13.3 million period-to-period primarily due to lower long-haul transportation revenues attributable to an increase in walk-up shipper volumes. Transportation volumes for Seaway increased 75 MBPD period-to-period (net to our interest).

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 June 30,		For the Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
Segment gross operating margin	$ 213.4	$ 194.4	$ 411.3	$ 365.3
Selected volumetric data:				
Natural gas pipeline transportation volumes (BBtus/d)	13,654	12,232	13,343	11,934

Second Quarter of 2018 Compared to Second Quarter of 2017. Gross operating margin from our Natural Gas Pipelines & Services segment for the second quarter of 2018 increased a net $19.0 million when compared to the second quarter of 2017.

Gross operating margin from our Permian Basin Gathering System increased $9.8 million quarter-to-quarter primarily due to an 87 BBtus/d increase in natural gas gathering volumes, which accounted a $6.4 million increase, and higher average gathering fees, which accounted for an additional $2.9 million increase. Gross operating margin from our Texas Intrastate System increased a net $9.5 million quarter-to-quarter primarily due to higher firm capacity reservation and other fees, which accounted for a $15.0 million increase, partially offset by higher maintenance and other operating costs, which accounted for a $4.9 million decrease. Transportation volumes on our Texas Intrastate System increased 66 BBtus/d quarter-to-quarter. Gross operating margin from our BTA Gathering System in East Texas increased $2.6 million quarter-to-quarter primarily due to an increase in gathering volumes of 85 BBtus/d.

With respect to our Louisiana assets, gross operating margin from our Haynesville Gathering System increased $4.9 million quarter-to-quarter primarily due to higher gathering volumes of 296 BBtus/d quarter-to-quarter whereas gross operating margin from our Acadian Gas System decreased $15.4 million quarter-to-quarter primarily due to $17.4 million of proceeds received in connection with a legal settlement in the second quarter of 2017. Transportation volumes for the Acadian Gas System increased 615 BBtus/d quarter-to-quarter, with the Haynesville Extension pipeline accounting for 524 BBtus/d of the increase.

Gross operating margin from our San Juan Gathering System increased $2.9 million quarter-to-quarter primarily due to higher natural gas sales margins. Gross operating margin from our Piceance Basin Gathering System increased $0.7 million quarter-to-quarter primarily due to a 107 BBtus/d increase in gathering volumes.

Gross operating margin from our natural gas marketing activities increased $3.8 million quarter-to-quarter primarily due to higher mark-to-market earnings, which accounted for $1.7 million of the increase, and higher average sales margins, which accounted for an additional $1.4 million increase.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Gross operating margin from our Natural Gas Pipelines & Services segment for the six months ended June 30, 2018 increased a net $46.0 million when compared to the six months ended June 30, 2017.

Gross operating margin from our Texas Intrastate System increased a net $19.1 million period-to-period primarily due to higher firm capacity reservation and other fees, which accounted for a $27.8 million increase, partially offset by higher maintenance and other operating costs, which accounted for an $8.6 million decrease. Transportation volumes on our Texas Intrastate System increased 55 BBtus/d period-to-period. Gross operating margin from our Permian Basin Gathering System increased $9.5 million period-to-period primarily due to a 103 BBtus/d increase in natural gas gathering volumes. Gross operating margin from our BTA Gathering System, which we acquired in April 2017, increased $7.5 million period-to-period.

Gross operating margin from our Haynesville Gathering System increased $11.1 million period-to-period primarily due to higher gathering volumes, which accounted for $5.6 million of the increase, and higher treating revenues, which accounted for an additional $3.4 million increase. Gross operating margin from our Acadian Gas System decreased a net $15.6 million period-to-period primarily due to the $17.4 million gain previously described that was recorded in the second quarter of 2017, partially offset by higher average firm capacity reservation fees on the Haynesville Extension pipeline, which accounted for a $4.2 million increase. Transportation volumes for the Haynesville Extension pipeline, which is a component of the Acadian Gas System, increased 463 BBtus/d and volumes for the Haynesville Gathering System increased 312 BBtus/d.

Gross operating margin from our Jonah and Piceance Basin Gathering Systems increased a combined $5.5 million period-to-period primarily due to a 260 BBtus/d increase in gathering volumes, which accounted for an $8.2 million increase, partially offset by lower average gathering fees, which accounted for a $2.1 million decrease. Gross operating margin from our San Juan Gathering System increased $5.1 million period-to-period primarily due to an increase in natural gas sales margins.

Gross operating margin from our natural gas marketing activities increased $2.6 million period-to-period primarily due to higher sales volumes.

Petrochemical & Refined Products Services

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
Segment gross operating margin:				
Propylene production and related activities	$ 126.5	$ 62.0	$ 255.9	$ 130.6
Butane isomerization and related operations	26.1	18.2	50.8	29.1
Octane enhancement and related plant operations	49.5	38.6	81.9	57.5
Refined products pipelines and related activities	72.1	69.5	153.0	146.2
Marine transportation and other	7.6	0.1	12.1	6.8
Total	$ 281.8	$ 188.4	$ 553.7	$ 370.2
Selected volumetric data:				
Propylene plant production volumes (MBPD)	100	81	98	81
Butane isomerization volumes (MBPD)	116	116	115	104
Standalone DIB processing volumes (MBPD)	89	81	83	82
Octane additive and related plant production volumes (MBPD)	30	30	28	25
Pipeline transportation volumes, primarily refined products and petrochemicals (MBPD)	771	800	810	813
Refined products and petrochemical marine terminal volumes (MBPD)	350	471	359	435

Propylene production and related activities

Second Quarter of 2018 Compared to Second Quarter of 2017. Gross operating margin from propylene production and related marketing activities for the second quarter of 2018 increased $64.5 million when compared to the second quarter of 2017. Gross operating margin from our PDH facility, which completed its commissioning (or start up) phase and began full commercial operations in the second quarter of 2018, was $46.2 million for the second quarter of 2018 on plant production volumes, including by-products, of 26 MBPD. Additionally, gross operating margin from our Mont Belvieu propylene fractionation plants increased $16.1 million quarter-to-quarter primarily due to higher average propylene sales margins.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Gross operating margin from propylene production and related marketing activities for the six months ended June 30, 2018 increased $125.3 million when compared to the six months ended June 30, 2017. Gross operating margin from our PDH facility was $51.8 million for the six months ended June 30, 2018. Propylene production volumes for the PDH facility, including by-products, averaged 20 MBPD for the six months ended June 30, 2018, which includes volumes for the first quarter of 2018 when the facility was still in its commissioning phase. Gross operating margin from our Mont Belvieu propylene fractionation plants increased $57.7 million period-to-period primarily due to higher average propylene sales margins.

Butane isomerization and related operations

Second Quarter of 2018 Compared to Second Quarter of 2017. Gross operating margin from butane isomerization and deisobutanizer ("DIB") operations for the second quarter of 2018 increased $7.9 million when compared to the second quarter of 2017 primarily due to higher average by-product sales prices in 2018.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Gross operating margin from butane isomerization and DIB operations for the six months ended June 30, 2018 increased $21.7 million when compared to the six months ended June 30, 2017. The increase in gross operating margin period-to-period is primarily due to higher by-product average sales prices and volumes, which accounted for an $11.1 million and $5.8 million increase, respectively.

Octane enhancement and related operations

Second Quarter of 2018 Compared to Second Quarter of 2017. Gross operating margin from our octane enhancement facility and high purity isobutylene plant for the second quarter of 2018 increased a combined $10.9 million when compared to the second quarter of 2017 primarily due to higher average sales margins, which accounted for a $6.0 million increase, and higher sales volumes, which accounted for an additional $5.7 million increase.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Gross operating margin from our octane enhancement facility and high purity isobutylene plant for the six months ended June 30, 2018 increased a combined $24.4 million when compared to the six months ended June 30, 2017 primarily due to higher sales volumes, which accounted for $18.5 million of the period-to-period increase.

Refined products pipelines and related activities

Second Quarter of 2018 Compared to Second Quarter of 2017. Gross operating margin from refined products pipelines and related marketing activities for the second quarter of 2018 increased a net $2.6 million when compared to the second quarter of 2017. Gross operating margin from our TE Products Pipeline and related refined products terminals increased a net $6.6 million quarter-to-quarter primarily due to higher NGL transportation volumes, which accounted for a $9.6 million increase, partially offset by lower refined product and petrochemical transportation volumes, which accounted for a $2.7 million decrease. NGL transportation volumes on our TE Products Pipeline increased 21 MBPD, while refined product and petrochemical transportation volumes decreased a combined 60 MBPD quarter-to-quarter.

Gross operating margin from our Houston Ship Channel and Beaumont refined products marine terminals decreased a combined $4.9 million quarter-to-quarter primarily due to lower storage revenues.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Gross operating margin from refined products pipelines and related marketing activities for the six months ended June 30, 2018 increased $6.8 million when compared to the six months ended June 30, 2017. Gross operating margin from our TE Products Pipeline and related refined products terminals increased a net $12.9 million period-to-period primarily due to higher NGL transportation volumes, which accounted for a $17.5 million increase, higher average transportation fees, which accounted for an additional $7.9 million increase, partially offset by higher maintenance and other operating costs, which accounted for a $10.1 million decrease, and lower refined product and petrochemical volumes, which accounted for a $4.1 million decrease. NGL transportation volumes on our TE Products Pipeline increased 19 MBPD, while refined product and petrochemical transportation volumes decreased a combined 47 MBPD period-to-period.

Gross operating margin from our Houston Ship Channel and Beaumont refined products marine terminals decreased a combined $8.5 million period-to-period primarily due to lower storage revenues.

Marine transportation and other

Second Quarter of 2018 Compared to Second Quarter of 2017. Gross operating margin from marine transportation for the second quarter of 2018 increased $7.5 million when compared to the second quarter of 2017 primarily due to an increase in marine transportation revenues attributable to higher vessel utilization quarter-to-quarter.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Gross operating margin from marine transportation for the six months ended June 30, 2018 increased $5.3 million when compared to the six months ended June 30, 2017 primarily due to higher vessel utilization period-to-period.

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 June 30, 2018, we had $3.59 billion of consolidated liquidity, which was comprised of $3.53 billion of available borrowing capacity under EPO's revolving credit facilities and $57.9 million of unrestricted cash on hand.

We may 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 June 30, 2018 for the years indicated (dollars in millions):

		Scheduled Maturities of Debt					
	Total	Remainder of 2018	2019	2020	2021	2022	Thereafter
Commercial Paper Notes	$ 1,970.0	$ 1,970.0	$ --	$ --	$ --	$ --	$ --
Senior Notes	20,750.0	--	1,500.0	1,500.0	1,325.0	650.0	15,775.0
Junior Subordinated Notes	3,191.7	--	--	--	--	--	3,191.7
Total	$ 25,911.7	$ 1,970.0	$ 1,500.0	$ 1,500.0	$ 1,325.0	$ 650.0	$ 18,966.7

Expected Renewal of 364-Day Credit Agreement

In September 2017, EPO entered into a 364-Day Credit Agreement that matures in September 2018 and allows EPO to borrow up to $1.5 billion in revolving loans at a variable interest rate for a term of 364 days. EPO expects to renew its 364-Day Credit Agreement during the third quarter of 2018 to extend its maturity date to September 2019. At June 30, 2018, there were no principal amounts outstanding under the existing 364-Day Credit Agreement.

Expected Redemption of Junior Subordinated Notes A

In July 2018, EPO notified its trustee and paying agent to redeem all of the $521.1 million outstanding principal amount of EPO's Junior Subordinated Notes A. These notes are redeemable at EPO's election at par (i.e., at a redemption price equal to the outstanding principal amount of such notes to be redeemed, plus accrued and unpaid interest thereon). On a short term basis, the redemption of EPO's Junior Subordinated Notes A is expected to be made using proceeds from the issuance of short term notes under EPO's commercial paper program or borrowings under its revolving credit facilities. The average variable interest rate paid on the Junior Subordinated Notes A for the six months ended June 30, 2018 was 5.61%. These notes bear a floating rate of three-month LIBOR plus approximately 3.7% and represent our highest cost variable-rate debt.

Increase in Amount Authorized under Commercial Paper Program
In June 2018, EPO increased the aggregate principal amount of short-term notes that it could issue (and have outstanding at any time) under its commercial paper program from $2.5 billion to $3.0 billion. The commercial paper program enables us to access typically lower short-term interest rates, which allows us to manage working capital and our overall cost of capital. All commercial paper notes issued under the program are senior unsecured obligations of EPO that are unconditionally guaranteed by Enterprise Products Partners L.P. As a back-stop to the commercial paper program, we intend to maintain a minimum available borrowing capacity under EPO's Multi-Year Revolving Credit Facility equal to the outstanding aggregate principal amount of EPO's commercial paper notes.

Issuance of $2.0 Billion of Senior Notes and $700 Million of Junior Subordinated Notes in February 2018
In February 2018, EPO issued $2.7 billion aggregate principal amount of notes comprised of (i) $750 million principal amount of senior notes due February 15, 2021 ("Senior Notes TT"), (ii) $1.25 billion principal amount of senior notes due February 15, 2048 ("Senior Notes UU") and (iii) $700 million principal amount of junior subordinated notes due February 15, 2078 ("Junior Subordinated Notes F").

Net proceeds from these offerings were used by EPO for the temporary repayment of amounts outstanding under its commercial paper program, general company purposes, and the redemption of all $682.7 million outstanding aggregate principal amount of its 7.034% Junior Subordinated Notes B.

Senior Notes TT were issued at 99.946% of their principal amount and have a fixed-rate interest rate of 2.80% per year. Senior Notes UU were issued at 99.865% of their principal amount and have a fixed-rate interest rate of 4.25% per year. Enterprise Products Partners L.P. has guaranteed the senior notes through an unconditional guarantee on an unsecured and unsubordinated basis.

The Junior Subordinated Notes F are redeemable at EPO's option, in whole or in part, on one or more occasions, on or after February 15, 2028 at 100% of their principal amount, plus any accrued and unpaid interest thereon, and bear interest at a fixed rate of 5.375% per year through February 14, 2028. Beginning February 15, 2028, the Junior Subordinated Notes F will bear interest at a floating rate based on a three-month LIBOR rate plus 2.57%, reset quarterly. Enterprise Products Partners L.P. has guaranteed the Junior Subordinated Notes F through an unconditional guarantee on an unsecured and subordinated basis.

Redemption of Junior Subordinated Notes B
On March 5, 2018, EPO redeemed all of the $682.7 million outstanding aggregate principal amount of its Junior Subordinated Notes B at a price equal to 100% of the principal amount of the notes being redeemed, plus all accrued and unpaid interest thereon to, but not including, the redemption date. The redemption of the 7.034% Junior Subordinated Notes B and the issuance of the 5.375% Junior Subordinated Notes F will result in annual interest savings to EPO of approximately $11.3 million.

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 distribution reinvestment plan ("DRIP") and employee unit purchase plan ("EUPP") for the six months ended June 30, 2018 (dollars in millions, number of units issued as shown):

	Number of Common Units Issued	Net Cash Proceeds Received
Three months ended March 31, 2018:		
Common units issued in connection with DRIP and EUPP	6,642,286	$ 177.0
Three months ended June 30, 2018:		
Common units issued in connection with DRIP and EUPP	3,234,804	84.0
Total common units issued during the six months ended June 30, 2018	9,877,090	$ 261.0

DRIP and EUPP
We have a registration statement on file with the SEC in connection with our 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. After taking into account the number of common units issued under the DRIP through June 30, 2018, we have the capacity to issue an additional 71,108,301 common units under this plan.

Pursuant to the DRIP, privately held affiliates of EPCO purchased $100 million of our common units in connection with the distribution paid in February 2018 and an additional $106 million of our common units in connection with the distribution paid on August 8, 2018.

In addition to the DRIP, we have registration statements on file with the SEC in connection with our EUPP. After taking into account the number of common units issued under the EUPP through June 30, 2018, we have the capacity to issue an additional 5,492,560 common units under this plan.

ATM Program
We have a registration statement on file with the SEC covering the issuance of up to $2.54 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 at-the-market ("ATM") program. No sales were made under this program during the six months ended June 30, 2018. After taking into account the aggregate sales price of common units sold under the ATM program in periods prior to fiscal 2018, we have the capacity to issue additional common units under the ATM program up to an aggregate sales price of $2.54 billion.

Use of Proceeds
The net cash proceeds we received from the issuance of common units during the six months ended June 30, 2018 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. At June 30, 2018 and December 31, 2017, our restricted cash amounts were $283.6 million and $65.2 million, respectively.

Additional cash may be restricted to maintain our commodity derivative instruments portfolio as prices fluctuate or margin requirements change. For information regarding our derivative instruments and hedging activities, see Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report. In addition, see Item 3, Quantitative and Qualitative Disclosures about Market Risk, within this Part I, Item 2.

Credit Ratings

As of August 1, 2018, the investment-grade credit ratings of EPO's long-term senior unsecured debt securities were BBB+ from Standard and Poor's, Baa1 from Moody's and BBB+ from Fitch Ratings. In addition, the credit ratings of EPO's short-term senior unsecured debt securities were A-2 from Standard and Poor's, P-2 from Moody's and F-2 from Fitch Ratings.

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

Cash Flows from Operating, Investing and Financing Activities

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

	For the Six Months Ended June 30,	
	2018	2017
Net cash flows provided by operating activities	$ 2,697.8	$ 2,334.9
Cash used in investing activities	2,089.6	1,298.6
Cash used in financing activities	337.0	1,389.9

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 2017 Form 10-K.

Comparison of Six Months Ended June 30, 2018 with Six Months Ended June 30, 2017

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 six months ended June 30, 2018 increased $362.9 million when compared to the same period in 2017. The increase in cash provided by operating activities was primarily due to:

- a $651.0 million increase in cash resulting from higher partnership earnings in the six months ended June 30, 2018 compared to the same period in 2017 (after adjusting our $161.7 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 $22.5 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 $310.6 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 six months ended June 30, 2018 increased $791.0 million when compared to the same period in 2017 primarily due to:

- an $808.0 million period-to-period increase in spending for consolidated property, plant and equipment (see "Capital Spending" within this Part I, Item 2 for additional information regarding our capital spending program); and

- a $21.8 million period-to-period increase in investments in unconsolidated affiliates primarily related to our crude oil joint ventures; partially offset by

- a $41.7 million period-to-period decrease in net cash used for business combinations. During the six months ended June 30, 2018, we used $150.6 million to acquire the remaining 50% equity interest in Delaware Processing. For the same period in 2017, we used $191.4 million to acquire the BTA Gathering System and related assets.

Financing activities. Cash used in financing activities for the six months ended June 30, 2018 decreased $1.05 billion when compared to the same period in 2017 primarily due to:

- a $915.2 million net cash inflow period-to-period attributable to the issuance of $2.7 billion in principal amount of senior and junior subordinated notes offset by the repayment of $1.78 billion in principal amount of senior and junior subordinated notes during the six months ended June 30, 2018 compared to no such issuances or repayments during the six months ended June 30, 2017. In addition, net issuances under EPO's commercial paper program were $214.3 million during the six months ended June 30, 2018 compared to net repayments of $331.4 million during the six months ended June 30, 2017; and

- a $206.6 million period-to-period increase in contributions from noncontrolling interests. In June 2018, an affiliate of Western acquired a noncontrolling 20% equity interest in our consolidated subsidiary that owns the Midland-to-ECHO Pipeline for $189.6 million in cash; partially offset by

- a $496.2 million period-to-period decrease in net cash proceeds from the issuance of common units. We issued an aggregate 9,877,090 common units, which generated $261.0 million of net cash proceeds, in connection with our DRIP and EUPP during the six months ended June 30, 2018. This compares to an aggregate 27,892,687 common units we issued in connection with our ATM, DRIP and EUPP during the six months ended June 30, 2017, which collectively generated $757.2 million of net cash proceeds; and

- an $89.5 million period-to-period increase in cash distributions paid to limited partners during the six months ended June 30, 2018 when compared to the six months ended June 30, 2017. 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.

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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Net income attributable to limited partners (1)	$ 673.8	$ 653.7	$ 1,574.5	$ 1,414.4
Adjustments to GAAP net income attributable to limited partners to derive non-GAAP distributable cash flow:				
Add depreciation, amortization and accretion expenses	458.3	406.5	889.3	808.8
Add non-cash asset impairment and related charges	15.9	14.0	16.8	25.2
Add net losses or add net gains attributable to asset sales	(0.9)	0.3	(1.4)	--
Add cash proceeds from asset sales	1.5	1.2	2.6	3.2
Subtract gain on step acquisition of unconsolidated affiliate	(2.4)	--	(39.4)	--
Add changes in fair value of Liquidity Option Agreement (2)	8.9	18.6	16.4	24.1
Add or subtract changes in fair market value of derivative instruments	322.1	(23.6)	459.0	(43.9)
Add cash distributions received from unconsolidated affiliates (3)	131.1	127.4	253.5	229.9
Subtract equity in income of unconsolidated affiliates	(122.3)	(107.0)	(238.0)	(201.8)
Subtract sustaining capital expenditures (4)	(72.8)	(62.3)	(139.1)	(110.3)
Add deferred income tax expense or subtract benefit, as applicable	11.1	0.6	10.0	0.7
Other, net	6.5	22.5	17.2	30.2
Distributable cash flow	$ 1,430.8	$ 1,051.9	$ 2,821.4	$ 2,180.5
Total cash distributions paid to limited partners with respect to period	$ 940.2	$ 906.6	$ 1,873.7	$ 1,799.4
Cash distributions per unit declared by Enterprise GP with respect to period (5)	$ 0.4300	$ 0.4200	$ 0.8575	$ 0.8350
Total distributable cash flow retained by partnership with respect to period (6)	$ 490.6	$ 145.3	$ 947.7	$ 381.1
Distribution coverage ratio (7)	1.5x	1.2x	1.5x	1.2x

(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 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.

(3) Reflects both distributions received on earnings from unconsolidated affiliates and those attributable to a return of capital from unconsolidated affiliates. For information regarding our unconsolidated affiliates, see Note 5 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

(4) Sustaining capital expenditures include cash payments and accruals applicable to the period.

(5) See Note 8 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for additional information regarding our quarterly cash distributions declared with respect to the periods presented.

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

(7) Distribution coverage ratio is determined by dividing distributable cash flow by total cash distributions paid to limited partners and in connection with distribution equivalent rights with respect to the period.

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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Net cash flows provided by operating activities	$ 1,464.2	$ 1,459.3	$ 2,697.8	$ 2,334.9
Adjustments to reconcile net cash flows provided by operating activities to distributable cash flow:				
Subtract sustaining capital expenditures	(72.8)	(62.3)	(139.1)	(110.3)
Add cash proceeds from asset sales	1.5	1.2	2.6	3.2
Net effect of changes in operating accounts	25.4	(370.9)	228.5	(82.1)
Other, net	12.5	24.6	31.6	34.8
Distributable cash flow	$ 1,430.8	$ 1,051.9	$ 2,821.4	$ 2,180.5

Capital Spending

We have approximately $5.2 billion of growth capital projects scheduled to be completed by the end of 2019. These projects include the:

- completion of joint venture-owned dock infrastructure in Corpus Christi designed to accommodate crude oil volumes (third quarter of 2018);
- completion of the Shin Oak NGL Pipeline (second quarter of 2019);
- expansions of our Front Range and Texas Express NGL pipelines (second and fourth quarters of 2019, respectively);
- completion of our isobutane dehydrogenation ("iBDH") unit (fourth quarter of 2019); and,
- completion of our ethylene export terminal (fourth quarter of 2019).

Our PDH facility completed its commissioning (or start up) phase and was placed into full commercial service in the second quarter of 2018. In addition, the first processing train at our Orla natural gas processing facility entered service in May 2018.

Based on information currently available, we expect our total growth capital spending for 2018 to approximate $3.8 billion to $4.0 billion, which includes the $150.6 million we spent to acquire the remaining 50% equity interest in Delaware Processing. We expect our sustaining capital expenditures for 2018 to approximate $315 million, of which $140.4 million was spent in the six months ended June 30, 2018.

Our forecast of capital spending for 2018 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 the primary elements of our capital spending for the periods indicated (dollars in millions):

	For the Six Months Ended June 30,	
	2018	2017
Capital spending for property, plant and equipment: (1)		
Growth capital projects (2)	$ 1,780.7	$ 1,003.6
Sustaining capital projects (3)	140.4	109.5
Total	$ 1,921.1	$ 1,113.1
Cash used for business combinations, net (4)	$ 149.7	$ 191.4
Investments in unconsolidated affiliates	$ 45.9	$ 24.1

(1) Growth and sustaining capital amounts presented in the table above are presented on a cash basis.
(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 presented for the six months ended June 30, 2018 represents the acquisition of the remaining 50% ownership interest in our Delaware Processing joint venture, which closed on March 29, 2018.

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 six months ended June 30, 2018 involved projects to support crude oil, natural gas and NGL production from the Permian Basin, export activities at our Gulf Coast terminal and spending on our iBDH unit. 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 Six Months Ended June 30, 2018 with Six Months Ended June 30, 2017

Total capital spending increased $788.1 million period-to-period primarily due to increased cash used for growth capital projects. Of the period-to-period increase in capital spending, the significant elements are as follows:

- Growth capital spending for projects to support Permian Basin production increased $488.8 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 facility and related pipelines and the Shin Oak NGL Pipeline.

- Growth capital spending for projects to expand and support export activities at EHT increased $230.3 million period-to-period. This amount includes $55.2 million of cash paid in April 2018 to acquire a 65-acre waterfront site located on the Houston Ship Channel that will serve as the next phase of expansion at EHT.

- Growth capital spending on our iBDH unit increased $177.0 million period-to-period.

- Growth capital spending to expand refined products capabilities at our Beaumont terminal increased $36.0 million period-to-period. These projects are expected to be completed in phases through the first quarter of 2019.

- Growth capital spending at our Mont Belvieu complex for our PDH facility and ninth NGL fractionator decreased $165.0 million period-to-period.

- Net cash used for business combinations decreased $41.7 million period-to-period. During the six months ended June 30, 2018, we used $150.6 million to acquire the remaining 50% equity interest in Delaware Processing. For the same period in 2017, we used $191.4 million to acquire the BTA Gathering System and related assets.

Pipeline Integrity Program

Our pipelines operate under safety regulations administered by the U.S. Department of Transportation ("DOT") that require 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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Recognized in operating costs and expenses	$ 27.3	$ 17.0	$ 44.3	$ 32.3
Reflected as a component of sustaining capital expenditures	12.9	13.1	20.6	21.3
Total	$ 40.2	$ 30.1	$ 64.9	$ 53.6

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2017 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 June 30, 2018 were approximately $25.91 billion compared to $24.78 billion at December 31, 2017. 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.

During the first six months of 2018, we entered into long-term product purchase commitments for crude oil with third party suppliers in order to meet future physical delivery obligations on our various systems. On a combined basis, these agreements increased our estimated long-term purchase obligations by approximately $1.2 billion over the next five years and $1.7 billion overall. Apart from these new agreements, there have been no other material changes in our consolidated purchase obligations since those reported in our 2017 Form 10-K.

Off-Balance Sheet Arrangements

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

Recent Accounting Developments

For information regarding recent developments involving changes in our accounting policies for revenue recognition, the presentation of restricted cash on the cash flow statement, and our work involving the new lease accounting standard, 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 15 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 and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

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

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

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

See Note 14 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 June 30, 2018 (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 (billion cubic feet ("Bcf"))	16.2	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchase of NGLs (million barrels ("MMBbls"))	0.9	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	0.9	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities (Bcf)	1.8	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	49.9	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	64.1	n/a	Cash flow hedge
NGLs inventory management activities (MMBbls)	0.5	n/a	Fair value hedge
Refined products marketing:			
Forecasted purchase of refined products (MMBbls)	0.9	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.2	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.1	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	9.1	4.1	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	9.9	4.1	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	92.5	2.9	Mark-to-market
Refined products risk management activities (MMBbls) (4)	1.4	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	68.5	29.0	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 2020, November 2018 and December 2020, respectively.
(3) Current and long-term volumes include 45.8 Bcf and 0.8 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.
(4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

At June 30, 2018, 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 shrinkage, 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, 2017**	**June 30, 2018**	**July 16, 2018**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (13.9)	$ (7.1)	$ (4.9)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(16.9)	(8.1)	(5.1)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(10.8)	(6.2)	(4.7)

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, 2017**	**June 30, 2018**	**July 16, 2018**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (76.4)	$ (1.7)	$ (13.8)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(126.1)	(22.6)	(63.7)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(26.8)	19.2	36.2

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, 2017**	**June 30, 2018**	**July 16, 2018**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (65.5)	$ (521.6)	$ (477.5)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(109.4)	(597.7)	(549.6)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(21.6)	(445.4)	(405.4)

The derivative liability for our crude oil marketing hedges increased from $65.5 million at December 31, 2017 to $521.6 million at June 30, 2018, which resulted in a $456.1 million decrease in the fair value of the crude oil marketing portfolio for the six months ended June 30, 2018. The derivative liability for the portfolio improved to $477.5 million at July 16, 2018 primarily due to the expiration of basis swap instruments since June 30, 2018. As noted in our discussion of results for the Crude Oil Pipelines & Services segment (Midland-to-ECHO Pipeline and related commercial activities), we entered into hedges of the crude oil commodity price differentials between the Midland and Houston markets and the Midland and Cushing markets. The mark-to-market losses we recognized during the three and six months ended June 30, 2018 were primarily due to the widening of the basis spreads between the Midland and Houston and Cushing markets.

Assuming no changes subsequent to June 30, 2018 in the variables underlying the portfolio's fair value, the derivative liability of $521.6 million at June 30, 2018 would be reversed upon cash settlement of the hedges, which would create unrealized mark-to-market gains and other comprehensive income as follows in the periods indicated (dollars in millions):

Third quarter of 2018	$ 158.8
Fourth quarter of 2018	198.5
Calendar year 2019	142.6
Calendar year 2020	6.2
Total mark-to-market gains	$ 506.1
Total other comprehensive income	15.5
Total comprehensive income	$ 521.6

As the non-cash mark-to-market gains attributable to the financial hedges are recognized in earnings, the corresponding actual losses on the financial hedges and related gains on the physical transactions will be simultaneously realized.

At June 30, 2018, approximately 50% of the Midland-to-ECHO Pipeline's uncommitted capacity available to us through 2020 was not hedged, thus providing us with potential upside to widening or downside to narrowing market spreads. The value of this unhedged capacity was approximately $363.8 million assuming that we hedged all such capacity at the prevailing crude oil commodity price differentials between Midland and Houston as of June 30, 2018.

The posting of additional cash may be required to maintain our commodity derivative instruments portfolio as prices fluctuate or margin requirements change. Our restricted cash balance increased from $283.6 million at June 30, 2018 to $316.0 million at July 16, 2018. In addition, we posted $238.3 million of cash and $85.0 million under stand-by letters of credit in connection with margin requirements on the Chicago Mercantile Exchange through July 16, 2018. The increase in restricted cash and other cash postings since June 30, 2018 is primarily due to changes in the initial margin requirements and fair value of our crude oil marketing transportation hedges.

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, the 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.

The following table summarizes our portfolio of 30-year forward starting swaps outstanding at June 30, 2018. 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	2 forward starting swaps	$175.0	2/2019	2.56%	Cash flow hedge

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, 2017	June 30, 2018	July 16, 2018
Fair value assuming no change in underlying interest rates	*Asset (Liability)*	$ (0.1)	$ 13.0	$ 12.4
Fair value assuming 10% increase in underlying interest rates	*Asset (Liability)*	13.8	22.3	21.6
Fair value assuming 10% decrease in underlying interest rates	*Asset (Liability)*	(15.1)	3.0	2.4

As a result of market conditions in January 2018, we elected to terminate $100 million notional amount of the forward starting swaps that were outstanding at December 31, 2017, which resulted in cash proceeds totaling $1.5 million for the first quarter of 2018.

In January 2018, we sold swaptions related to our interest rate hedging activities that resulted in the recognition of $7.2 million of cash gains that were reflected as a reduction in interest expense for the first quarter of 2018. Likewise, in April 2018, we sold swaptions related to our interest rate hedging activities that resulted in the recognition of $11.8 million of cash gains that were reflected as a reduction in interest expense for the second quarter of 2018. The January 2018 swaptions expired in March 2018 and the April 2018 swaptions expired in June 2018.

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 second quarter of 2018, 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.

In February 2018, we received a Notice of Violation from the New Mexico Environment Department ("NMED") for air permit violations at our South Eddy Cryo Plant in New Mexico. Based on subsequent discussions with the NMED, the eventual resolution of this matter may result in monetary sanctions in excess of $0.1 million. We do not expect such expenditures to be material to our consolidated financial statements.

For additional information regarding our litigation matters, see "Litigation" under Note 16 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 2017 Form 10-K, in addition to other information in such annual report. The risk factors set forth in our 2017 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.*

Recent Issuance of Unregistered Securities

On April 5, 2018, we issued 1,223,242 common units to an unaffiliated third party in a private placement exempt from the registration requirements of the Securities Act of 1933, as amended (pursuant to Section 4(a)(2) thereof), in connection with our acquisition of certain waterfront property on the Houston Ship Channel. The agreement pursuant to which we issued these common units contained customary representations, warranties and covenants, including the certification of facts relating to the availability of the exemption described above.

Other than as described above, there were no sales of unregistered equity securities during the period ended June 30, 2018.

Issuer Purchases of Equity Securities

The following table summarizes our repurchase activity during the six months ended June 30, 2018 in connection with the vesting of 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
January 2018 (1)	2,559	$ 27.73	--	--
February 2018 (2)	945,409	$ 26.40	--	--
March 2018 (3)	1,810	$ 25.68	--	--
May 2018 (4)	34,827	$ 26.85	--	--

(1) Of the 8,000 phantom unit awards that vested in January 2018 and converted to common units, 2,559 units were sold back to us by employees to cover related withholding tax requirements.
(2) Of the 3,156,811 phantom unit awards that vested in February 2018 and converted to common units, 945,409 units were sold back to us by employees to cover related withholding tax requirements.
(3) Of the 6,050 phantom unit awards that vested in March 2018 and converted to common units, 1,810 units were sold back to us by employees to cover related withholding tax requirements.
(4) Of the 115,115 phantom unit awards that vested in May 2018 and converted to common units, 34,827 units were sold back to us by employees to cover related withholding tax requirements.

Item 3. *Defaults Upon Senior Securities.*

None.

Item 4. *Mine Safety Disclosures.*

Not applicable.

Item 5. ***Other Information.***

None.

Item 6. ***Exhibits.***

Exhibit Number	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
2.6	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed June 29, 2009).
2.7	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 29, 2009).
2.8	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise ETE LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2010).
2.9	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products GP, LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed September 7, 2010).
2.10	Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010).
2.11	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
2.12	Contribution and Purchase Agreement, dated as of October 1, 2014, by and among Enterprise Products Partners L.P., Oiltanking Holding Americas, Inc. and OTB Holdco, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2014).

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).
2.14	Amendment No. 1 dated as of June 6, 2018 to Contribution and Purchase Agreement, by and among Enterprise Products Partners L.P., Oiltanking Holding Americas, Inc., Enterprise Products Holdings LLC and Marquard & Bahls, AG (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 12, 2018).
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	Amendment No. 3 to the Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated as of November 28, 2017 (incorporated by reference to Exhibit 3.1 to Form 8-K filed December 1, 2017).
3.7	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).
3.8	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).
3.9	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).
3.10	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).
3.11	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).
3.12	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).
3.13	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	Amended and Restated Eighth Supplemental Indenture, dated as of August 25, 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 August 25, 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	Thirtieth Supplemental Indenture, dated as of February 15, 2018, 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 February 15, 2018).
4.28	Thirty-First Supplemental Indenture, dated as of February 15, 2018, 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 15, 2018).
4.29	Form of Global Note representing \$499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.30	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).
4.31	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).

4.32	Form of Global Note representing an aggregate of $550.0 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 August 25, 2006).
4.33	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).
4.34	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).
4.35	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).
4.36	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).
4.37	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).
4.38	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).
4.39	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).
4.40	Form of Global Note representing $1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.41	Form of Global Note representing $600.0 million principal amount of 6.45% Senior Notes due 2040 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.42	Form of Global Note representing $750.0 million principal amount of 3.20% Senior Notes due 2016 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.43	Form of Global Note representing $750.0 million principal amount of 5.95% Senior Notes due 2041 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.44	Form of Global Note representing $650.0 million principal amount of 4.05% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.45	Form of Global Note representing $600.0 million principal amount of 5.70% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.46	Form of Global Note representing $750.0 million principal amount of 4.85% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
4.47	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).
4.48	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).
4.49	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).

4.50	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).
4.51	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).
4.52	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).
4.53	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).
4.54	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).
4.55	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).
4.56	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).
4.57	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).
4.58	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).
4.59	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).
4.60	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).
4.61	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).
4.62	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).
4.63	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).
4.64	Form of Global Note representing $750.0 million principal amount of 2.80% Senior Notes due 2021 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.4 to Form 8-K filed February 15, 2018).
4.65	Form of Global Note representing $1.25 billion principal amount of 4.25% Senior Notes due 2048 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.4 to Form 8-K filed February 15, 2018).
4.66	Form of Global Note representing $700 million principal amount of Junior Subordinated Notes F due 2078 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed February 15, 2018).
4.67	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).

4.68	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).
4.69	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).
4.70	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).
4.71	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).
4.72	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).
4.73	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).
4.74	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).
4.75	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).
4.76	Sixth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.12 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.77	Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.13 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.78	Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.79	Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed March 1, 2010).
4.80	Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P.

	and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007).
4.81	First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007).
4.82	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).
4.83	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).
4.84	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).
4.85	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).
12.1#	Computation of ratio of earnings to fixed charges for the six months ended June 30, 2018 and each of the years ended December 31, 2017, 2016, 2015, 2014 and 2013.
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 six months ended June 30, 2018.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the six months ended June 30, 2018.
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 six months ended June 30, 2018.
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 six months ended June 30, 2018.
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 six months ended June 30, 2018.
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 six months ended June 30, 2018.
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 August 8, 2018.

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