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

FORM 10-K

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

For the fiscal year ended December 31, 2017

OR

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

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of Registrant as Specified in Its Charter)

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

1100 LOUISIANA STREET, 10th FLOOR, HOUSTON, TEXAS 77002
(Address of Principal Executive Offices) (Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
Common Units	New York Stock Exchange

Securities to be registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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 Website, 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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 ☐ 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 ☑

The aggregate market value of the partnership's common units held by non-affiliates at June 30, 2017 (the last business day of the registrant's most recently completed second fiscal quarter) was $39.61 billion based on a closing price on that date of $27.08 per common unit on the New York Stock Exchange Composite ticker tape. There were 2,161,094,920 common units outstanding at January 31, 2018.

ENTERPRISE PRODUCTS PARTNERS L.P.
TABLE OF CONTENTS

KEY REFERENCES USED IN THIS REPORT

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 December 31, 2017.

References to “EFS Midstream” mean EFS Midstream LLC, which we acquired in July 2015 from affiliates of Pioneer Natural Resources Company and Reliance Industries Limited. See Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding this acquisition.

References to “Offshore Business” refer to the Gulf of Mexico operations we sold to Genesis Energy, L.P. in July 2015. See Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding this sale.

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

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report on Form 10-K for the year ended December 31, 2017 (our "annual report") 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 this annual 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 annual 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.

PART I

Item 1 and 2. *Business and Properties.*

General

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

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and 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. Our principal executive offices are located at 1100 Louisiana Street, 10th Floor, Houston, Texas 77002, our telephone number is (713) 381-6500 and our website address is www.enterpriseproducts.com.

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. As of February 1, 2018, there were approximately 7,000 EPCO personnel who spend all or a substantial portion of their time engaged in our business. For additional information regarding the ASA, see "EPCO ASA" under Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Business Strategy

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the U.S., Canada and Gulf of Mexico with domestic consumers and international markets. Our business strategy seeks to leverage this network to:

- capitalize on expected demand growth, including exports, for natural gas, NGLs, crude oil and petrochemical and refined products;

- maintain a diversified portfolio of midstream energy assets and expand this asset base through growth capital projects and accretive acquisitions of complementary midstream energy assets;

- enhance the stability of our cash flows by investing in pipelines and other fee-based businesses; and

- share capital costs and risks through joint ventures or alliances with strategic partners, including those that provide processing, throughput or feedstock volumes for growth capital projects or the purchase of such projects' end products.

Commercial and Liquidity Outlook for 2018

For information regarding our commercial and liquidity outlook for the year ending December 31, 2018, see "General Outlook for 2018" included under Part II, Item 7 of this annual report.

Major Customer Information

Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base. Our largest non-affiliated customer for 2017 was Vitol Holding B.V. and its affiliates (collectively, "Vitol"), which accounted for 11.2% of our consolidated revenues. Vitol is a global energy and commodity trading company. See Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for additional information regarding our largest non-affiliated customers for the years ended December 31, 2017, 2016 and 2015.

Business Segments

General

The following sections provide an overview of our business segments, including information regarding principal products produced and/or services rendered and properties owned. 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.

Our results of operations and financial condition are subject to certain significant risks. Factors that can affect the demand for our products and services include domestic and international economic conditions, the market price and demand for energy, the cost to develop natural gas and crude oil reserves in the U.S., federal and state regulation, the cost and availability of capital to energy companies to invest in upstream exploration and production activities and the credit quality of our customers. For information regarding such risks, see Part I, Item 1A of this annual report. In addition, our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental, safety and other matters. For a discussion of the principal effects of such laws and regulations on our business activities, see "Regulatory Matters" within this Part I, Item 1 and 2 discussion.

For management's discussion and analysis of our results of operations, liquidity and capital resources and capital spending program, see Part II, Item 7 of this annual report.

For detailed financial information regarding our business segments, see Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report. Such financial information is incorporated by reference into this Part I, Item 1 and 2 discussion.

NGL Pipelines & Services Segment

Our NGL Pipelines & Services business segment includes natural gas processing plants and related NGL marketing activities; approximately 19,600 miles of NGL pipelines; NGL and related product storage facilities; and 14 NGL fractionators. This segment also includes our LPG and ethane export terminals and related operations.

Natural gas processing plants and related NGL marketing activities

At the core of our natural gas processing business are 27 processing plants located in Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. The results of operations from our natural gas processing plants are primarily dependent on the difference between the revenues we earn from extracting NGLs (in terms of cash processing fees and/or the value of any retained NGLs) and the cost of natural gas and other operating costs incurred in connection with such extraction activities.

In its raw form, natural gas produced at the wellhead (especially in association with crude oil) contains varying amounts of NGLs, such as ethane and propane. Natural gas streams containing NGLs are usually not acceptable for transportation in natural gas pipelines or for commercial use as a fuel; therefore, the raw (or unprocessed) natural gas streams must be transported to a natural gas processing plant to remove the NGLs and impurities. Once the natural gas is processed and NGLs and impurities are removed, the natural gas meets pipeline and commercial quality specifications. On an energy-equivalent basis, most NGLs generally have greater economic value as feedstock for petrochemical and motor gasoline production than as components of a natural gas stream.

Once mixed NGLs are extracted by a natural gas processing plant, they are typically transported to a centralized fractionation facility for separation into purity NGL products (ethane, propane, normal butane, isobutane and natural gasoline). Purity NGL products are used as feedstocks by the petrochemical industry, as feedstocks by refineries in the production of motor gasoline and as fuel by industrial and residential consumers, as follows:

- Ethane is primarily used in the petrochemical industry as a feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products.

- Propane is used for heating, as an engine and industrial fuel, and as a petrochemical feedstock in the production of ethylene and propylene.

- Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient of synthetic rubber), as a blendstock for motor gasoline, and to produce isobutane through isomerization.

- Isobutane is fractionated from mixed butane (a mixed stream of normal butane and isobutane) or produced from normal butane through the process of isomerization, and is used in refinery alkylation to enhance the octane content of motor gasoline, in the production of isooctane and other octane additives, and in the production of propylene oxide.

- Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline, diluent in crude oil to aid in transportation, and as a petrochemical feedstock.

In our natural gas processing business, contracts are either fee-based, commodity-based or a combination of the two. Generally, our natural gas processing agreements have terms ranging from month-to-month to life of the producing lease. Intermediate terms of one to ten years are also common in such agreements. In recent years, our portfolio of natural gas processing contracts has become increasingly weighted towards those with fee-based terms as producers seek to maximize the value of their production by retaining all or a portion of the NGLs extracted from their natural gas stream. As of December 31, 2017, we estimate that the terms of approximately 44.1% of our current portfolio of natural gas processing contracts (based on natural gas inlet volumes) were entirely fee-based, with an additional 26.2% of this portfolio reflecting a combination of fee-based and commodity-based terms. The terms of the remaining 29.7% of our portfolio of natural gas processing contracts were entirely commodity-based. 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. To the extent we earn all or a portion of the extracted NGLs as consideration for our processing services, we refer to such volumes as our "equity NGL production."

The value of natural gas that is removed from the processed stream as a result of NGL extraction (i.e., the "shrinkage") and the value of natural gas that is consumed as plant fuel are significant costs of natural gas processing. To the extent that we are obligated under keepwhole and margin-band contracts to compensate the producer for shrinkage and plant fuel, we are exposed to fluctuations in the price of natural gas; however, margin-band contracts typically contain terms that limit our exposure to such risks. Under the terms of our other processing arrangements (i.e., those agreements with fee-based, percent-of-liquids and percent-of-proceeds terms), the producer typically bears the cost of shrinkage. If the operating costs of a natural gas processing plant are higher than the incremental value of the NGL products that would be extracted, then recovery levels of certain NGL products, principally ethane, may be purposefully reduced. This scenario is typically referred to as "ethane rejection" and leads to a reduction in NGL volumes available for subsequent transportation, fractionation, storage and marketing.

Our NGL marketing activities entail term and spot sales of NGLs, which we take title to through our natural gas processing activities (i.e., our equity NGL production) and open market and contract purchases. The results of operations for NGL marketing are primarily dependent on the difference between NGL sales prices and the associated purchase and other costs, including those costs attributable to the use of our other assets. In general, sales prices referenced in the underlying contracts are market-based and may include pricing adjustments for factors such as location, timing or product quality. Market prices for NGLs are subject to fluctuations in response to changes in supply and demand and a variety of additional factors that are beyond our control. We attempt to mitigate these price risks through the use of commodity derivative instruments. For a discussion of our commodity hedging program, see Part II, Item 7A of this annual report.

Our NGL marketing activities utilize a fleet of approximately 820 railcars, the majority of which are leased from third parties. These railcars are used to deliver feedstocks to our facilities and to distribute NGLs throughout the U.S. and parts of Canada. We have rail loading and unloading capabilities at certain of our terminal facilities in Arizona, Kansas, Louisiana, Minnesota, Mississippi, New York, North Carolina and Texas. These facilities service both our rail shipments and those of our customers. Our NGL marketing activities also utilize a fleet of approximately 121 tractor-trailer tank trucks, the majority of which we lease and operate, that are used to transport LPG for us and on behalf of third parties.

The following table presents selected information regarding our natural gas processing facilities at February 1, 2018 listed in order of net gas processing capacity (net to our interest):

Plant Name	Location(s)	Production Region Served	Our Ownership Interest		Net Gas Processing Capacity to Us (MMcf/d) (1)	Total Gas Processing Capacity of Plant (MMcf/d)
Meeker	Colorado	Piceance	100.0%		1,800	1,800
Pioneer (two facilities)	Wyoming	Green River	100.0%		1,400	1,400
Yoakum	Texas	Eagle Ford	100.0%		1,050	1,050
Pascagoula	Mississippi	Gulf of Mexico	100.0%		1,000	1,000
Chaco	New Mexico	San Juan	100.0%		600	600
North Terrebonne	Louisiana	Gulf of Mexico	60.6%	(2)	576	950
Neptune	Louisiana	Gulf of Mexico	66.0%	(2)	430	650
Sea Robin	Louisiana	Gulf of Mexico	53.6%	(2)	348	650
Thompsonville	Texas	Eagle Ford	100.0%		330	330
Shoup	Texas	Eagle Ford	100.0%		280	280
Armstrong	Texas	Eagle Ford	100.0%		250	250
Gilmore	Texas	Frio-Vicksburg	100.0%		250	250
Toca	Louisiana	Gulf of Mexico	73.2%	(2)	220	300
San Martin	Texas	Eagle Ford	100.0%		200	200
South Eddy (3)	New Mexico	Delaware	100.0%		200	200
Delmita	Texas	Frio-Vicksburg	100.0%		145	145
Carlsbad	New Mexico	Delaware	100.0%		130	130
Panola (4)	Texas	Cotton Valley	100.0%		125	125
Sonora	Texas	Strawn	100.0%		120	120
Shilling	Texas	Eagle Ford	100.0%		110	110
Venice	Louisiana	Gulf of Mexico	13.1%	(5)	98	750
Indian Springs	Texas	Wilcox-Woodbine	75.0%	(2)	90	120
Burns Point	Louisiana	Gulf of Mexico	50.0%	(2)	80	160
Waha (6)	Texas	Delaware	50.0%		75	150
Chaparral	New Mexico	Delaware	100.0%		45	45
Fairway (4)	Texas	Cotton Valley	100.0%		5	5
Total					9,957	11,770

(1) The approximate net gas processing capacity does not necessarily correspond to our ownership interest in each facility. The capacity is based on a variety of factors such as the level of volumes an owner processes at the facility and contractual arrangements with joint owners.
(2) We proportionately consolidate our undivided interest in these operating assets.
(3) We completed construction and placed the South Eddy facility into service in May 2016.
(4) Acquired in connection with Azure acquisition in April 2017.
(5) Our ownership in the Venice plant is held indirectly through our equity method investment in Venice Energy Services Company, L.L.C.
(6) We completed construction and placed the Waha facility into service in August 2016. Our ownership in the Waha plant is held indirectly through our equity method investment in Delaware Basin Gas Processing LLC.

We operate all of our natural gas processing facilities except for the Venice plant. On a weighted-average basis, utilization rates for our natural gas processing plants were approximately 52.0%, 50.8% and 56.7% for the years ended December 31, 2017, 2016 and 2015, respectively.

Orla natural gas processing facility
An area of focus for us has been the development of midstream infrastructure serving producers in the Delaware Basin in West Texas and southeast New Mexico. In June 2016, we announced plans to construct a cryogenic natural gas processing plant and related natural gas gathering lines near Orla, Texas in Reeves County. Mixed NGLs extracted at the Orla facility will be delivered into our fully integrated NGL system, including the recently announced Shin Oak NGL Pipeline. Residue natural gas volumes from the facility will be transported to the Waha area using our Texas Intrastate System. The Orla facility is designed to support the continued growth in NGL-rich natural gas production from the Delaware Basin and is supported by long-term customer commitments. We will own and operate the Orla facility.

The Orla facility will be completed in three stages. The first processing train ("Orla I") will have natural gas processing capacity of 300 MMcf/d and the capability to extract more than 40 MBPD of mixed NGLs. This first plant, along with Orla's related pipeline infrastructure, are expected to begin service in the second quarter of 2018. Construction of a second processing train ("Orla II") was announced in June 2017. This second plant is expected to add 300 MMcf/d of incremental processing capacity to the Orla facility and increase the extraction rate for mixed NGLs up to 80 MBPD. Orla II is expected to begin service in the fourth quarter of 2018. In January 2018, we announced plans to construct a third processing train ("Orla III") at the Orla facility. Once Orla III is completed, the Orla facility will have 900 MMcf/d of total processing capacity and allow us to extract up to 120 MBPD of mixed NGLs. Orla III is expected to begin service in the third quarter of 2019.

NGL pipelines
Our NGL pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities, refineries and import terminals to fractionation plants and storage facilities; gather and distribute purity NGL products to and from fractionation plants, storage and terminal facilities, petrochemical plants, export facilities and refineries; and deliver propane and ethane to destinations along our various pipeline systems.

The results of operations from our NGL pipelines are primarily dependent upon the volume of NGLs transported (or capacity reserved) and the associated fees we charge for such transportation services. Transportation fees charged to shippers are based on either tariffs regulated by federal governmental agencies, including the Federal Energy Regulatory Commission ("FERC"), or contractual arrangements. See "Regulatory Matters" within this Part I, Item 1 and 2 discussion for additional information regarding governmental oversight of liquids pipelines.

Excluding linefill volumes and volumes shipped in connection with our marketing activities, we typically do not take title to the products transported by third party shippers on our NGL pipelines; rather, the third party shipper retains title and the associated commodity price risk.

The following table presents selected information regarding our NGL pipelines at February 1, 2018:

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)
NGL pipelines:			
Mid-America Pipeline System (1)	Midwest and Western U.S.	100.0%	8,083
South Texas NGL Pipeline System	Texas	100.0%	1,916
Dixie Pipeline (1)	South and Southeastern U.S.	100.0%	1,306
Seminole Pipeline (1)	Texas	100.0%	1,248
ATEX (1)	Texas to Midwest and Northeast U.S.	100.0%	1,192
Chaparral NGL System (1)	Texas, New Mexico	100.0%	1,085
Louisiana Pipeline System (1)	Louisiana	100.0%	950
Texas Express Pipeline (1)	Texas	35.0% (2)	594
Skelly-Belvieu Pipeline (1)	Texas, Oklahoma	50.0% (3)	572
Front Range Pipeline (1)	Colorado, Oklahoma, Texas	33.3% (4)	447
Aegis Ethane Pipeline (1)	Texas, Louisiana	100.0%	280
Houston Ship Channel Pipeline System	Texas	100.0%	274
Rio Grande Pipeline (1)	Texas	70.0% (5)	249
Panola Pipeline (1)	Texas	55.0% (6)	249
Lou-Tex NGL Pipeline (1)	Texas, Louisiana	100.0%	206
Promix NGL Gathering System	Louisiana	50.0% (7)	201
Tri-States NGL Pipeline (1)	Alabama, Mississippi, Louisiana	83.3% (8)	168
Texas Express Gathering System	Texas	45.0% (9)	116
Others (seven systems) (10)	Various	Various (11)	423
Total			19,559

(1) Interstate transportation services provided by these liquids pipelines, in whole or part, are regulated by federal governmental agencies.
(2) Our ownership interest in the Texas Express Pipeline is held indirectly through our equity method investment in Texas Express Pipeline LLC.
(3) Our ownership interest in the Skelly-Belvieu Pipeline is held indirectly through our equity method investment in Skelly-Belvieu Pipeline Company, L.L.C.
(4) Our ownership interest in the Front Range Pipeline is held indirectly through our equity method investment in Front Range Pipeline LLC.
(5) We own a 70% consolidated interest in the Rio Grande Pipeline through our majority owned subsidiary, Rio Grande Pipeline Company.
(6) We own a 55% consolidated interest in the Panola Pipeline through our majority owned subsidiary, Panola Pipeline Company, LLC.
(7) Our ownership interest in the Promix NGL Gathering System is held indirectly through our equity method investment in K/D/S Promix, L.L.C. ("Promix").
(8) We own an 83.3% consolidated interest in the Tri-States NGL Pipeline through our majority owned subsidiary, Tri-States NGL Pipeline, L.L.C.
(9) Our ownership interest in the Texas Express Gathering System is held indirectly through our equity method investment in Texas Express Gathering LLC ("Texas Express Gathering").
(10) Includes our Belle Rose and Wilprise pipelines located in the coastal regions of Louisiana; two Port Arthur pipelines located in southeast Texas; our San Jacinto pipeline located in East Texas; our Permian NGL lateral pipelines located in West Texas; Leveret pipeline in West Texas and New Mexico; and a pipeline in Colorado associated with our Meeker facility. Transportation services provided by the Wilprise, Permian NGL and Leveret pipelines are regulated by federal governmental agencies.
(11) We own a 74.7% consolidated interest in the 30-mile Wilprise pipeline through our majority owned subsidiary, Wilprise Pipeline Company, LLC. We proportionately consolidate our 50% undivided interest in a 45-mile segment of the Port Arthur pipelines. The remainder of these NGL pipelines are wholly owned.

The maximum number of barrels per day that our NGL pipelines can transport depends on the operating rates achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and the mix of products being transported). As a result, we measure the utilization rates of our NGL pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 3,168 MBPD, 2,965 MBPD and 2,700 MBPD during the years ended December 31, 2017, 2016 and 2015, respectively.

The following information describes each of our principal NGL pipelines. We operate our NGL pipelines with the exception of the Skelly-Belvieu Pipeline and Texas Express Gathering System.

- The *Mid-America Pipeline System* is an NGL pipeline system consisting of four primary segments: the 3,167-mile Rocky Mountain pipeline, the 2,146-mile Conway South pipeline, the 2,138-mile Conway North pipeline, and the 632-mile Ethane-Propane Mix pipeline. The Mid-America Pipeline System operates in 13 states: Colorado, Illinois, Iowa, Kansas, Minnesota, Missouri, Nebraska, New Mexico, Oklahoma, Texas, Utah, Wisconsin and Wyoming. The Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs NGL hub located on the Texas-New Mexico border. The Conway North segment links the NGL hub at Conway, Kansas to refineries, petrochemical plants and propane markets in the upper Midwest. NGL hubs such as those at Hobbs and Conway provide buyers and sellers a centralized location for the storage and pricing of products, while also providing connections to intrastate and/or interstate pipelines. The Ethane-Propane Mix segment transports ethane/propane mix primarily to petrochemical plants in Iowa and Illinois from the NGL hub at Conway. The Conway South pipeline connects the Conway hub with Kansas refineries and provides bi-directional transportation of NGLs between the Conway and Hobbs hubs. At the Hobbs NGL hub, the Mid-America Pipeline System interconnects with our Seminole Pipeline and Hobbs NGL fractionation and storage facility. The Mid-America Pipeline System is also connected to 18 non-regulated NGL terminals that we own and operate.

  Volumes transported on the Mid-America Pipeline System primarily originate from natural gas processing plants in the Rocky Mountains and Mid-Continent regions, as well as NGL fractionation and storage facilities in Kansas and Texas.

- The *South Texas NGL Pipeline System* is a network of NGL gathering and transportation pipelines located in South Texas. This system gathers and transports mixed NGLs from natural gas processing plants in South Texas (owned by us or third parties) to our NGL fractionators in South Texas and Mont Belvieu, Texas. In addition, this system transports purity NGL products from our South Texas NGL fractionators to refineries and petrochemical plants located between Corpus Christi, Texas and Houston, Texas and within the Texas City-Houston area, as well as to interconnects with common carrier NGL pipelines. The South Texas NGL Pipeline System extends our ethane header system from Mont Belvieu, Texas to Corpus Christi, Texas. The South Texas NGL Pipeline System also connects our South Texas NGL fractionators with our storage facility in Mont Belvieu, Texas. The pipeline system includes a 168-mile segment that transports mixed NGLs from our Yoakum natural gas processing plant to our Mont Belvieu NGL fractionation and storage complex. In addition, a 173-mile segment extends from our Yoakum facility to a third party natural gas processing plant located in LaSalle County, Texas, and provides NGL pipeline takeaway capacity for additional third party gas plants.

- The *Dixie Pipeline* extends from southeast Texas to markets in the southeastern U.S., and transports propane and other NGLs. Propane supplies transported on this system primarily originate from southeast Texas, south Louisiana and Mississippi. This system operates in seven states: Alabama, Georgia, Louisiana, Mississippi, North Carolina, South Carolina and Texas, and is connected to eight non-regulated propane terminals that we own and operate.

- The *Seminole Pipeline* transports NGLs from the Hobbs hub and the Permian Basin area of West Texas to markets in southeast Texas including our NGL fractionation facility in Mont Belvieu, Texas. NGLs originating on the Mid-America Pipeline System are a significant source of throughput for the Seminole Pipeline, which is comprised of two parallel pipelines to Mont Belvieu – the Seminole Blue and Seminole Red lines.

- The *ATEX*, or Appalachia-to-Texas Express, pipeline primarily transports ethane in southbound service from four third-party owned NGL fractionation plants located in Ohio, Pennsylvania and West Virginia to our Mont Belvieu storage complex. The ethane extracted by these fractionation facilities originates from the Marcellus and Utica Shale production areas. ATEX operates in nine states: Arkansas, Illinois, Indiana, Louisiana, Missouri, Ohio, Pennsylvania, Texas and West Virginia.

- The *Chaparral NGL System* transports mixed NGLs from natural gas processing plants in West Texas and New Mexico to Mont Belvieu, Texas. This system consists of the 906-mile Chaparral pipeline and the 179-mile Quanah pipeline. Interstate and intrastate transportation services provided by the Chaparral pipeline are regulated; however, transportation services provided by the Quanah pipeline are not.

- The *Louisiana Pipeline System* is a network of NGL pipelines located in southern Louisiana. This system transports NGLs originating in Louisiana and Texas to refineries and petrochemical plants located along the Mississippi River corridor in southern Louisiana. This system also provides transportation services for our natural gas processing plants, NGL fractionators and other assets located in Louisiana. Originating from a central point in Henry, Louisiana, pipelines extend west to Lake Charles, Louisiana, north to an interconnect with the Dixie Pipeline at Breaux Bridge, Louisiana and east in Louisiana, where our Promix and Norco NGL fractionators and related storage facilities are located.

- The *Texas Express Pipeline* extends from Skellytown, Texas to our NGL fractionation and storage complex at Mont Belvieu, Texas. Mixed NGLs from the Rocky Mountains, Permian Basin and Mid-Continent regions are delivered to the Texas Express Pipeline via an interconnect with our Mid-America Pipeline System near Skellytown. The Texas Express Pipeline also transports mixed NGLs from two gathering systems owned by Texas Express Gathering to Mont Belvieu. In addition, mixed NGLs from the Denver-Julesburg Basin are transported to the Texas Express Pipeline using the Front Range Pipeline.

- The *Skelly-Belvieu Pipeline* transports mixed NGLs from Skellytown, Texas to Mont Belvieu, Texas. The Skelly-Belvieu Pipeline receives a significant quantity of NGLs through pipeline interconnects with our Mid-America Pipeline System in Skellytown.

- The *Front Range Pipeline* transports mixed NGLs from natural gas processing plants located in the Denver-Julesburg Basin in Colorado to an interconnect with our Texas Express Pipeline and Mid-America Pipeline System and other third party facilities at Skellytown, Texas.

- The *Aegis Ethane Pipeline* ("Aegis") was completed in December 2015 and delivers purity ethane to petrochemical facilities along the southeast Texas and Louisiana Gulf Coast. Aegis, when combined with a portion of our South Texas NGL Pipeline System, creates an ethane header system stretching approximately 500 miles between Corpus Christi, Texas and the Mississippi River in Louisiana.

- The *Houston Ship Channel Pipeline System* connects our Mont Belvieu complex to our Houston Ship Channel import/export terminals and various third party petrochemical plants, refineries and other pipelines located along the Houston Ship Channel.

- The *Rio Grande Pipeline* transports mixed NGLs from near Odessa, Texas to a pipeline interconnect at the Mexican border south of El Paso, Texas.

- The *Panola Pipeline* transports mixed NGLs from points near Carthage, Texas to Mont Belvieu and supports the Haynesville and Cotton Valley oil and gas production areas.

- The *Lou-Tex NGL Pipeline* system transports mixed NGLs, purity NGL products and refinery grade propylene ("RGP") between the Louisiana and Texas markets.

- The *Promix NGL Gathering System* gathers mixed NGLs from natural gas processing plants in southern Louisiana for delivery to our Promix NGL fractionator.

- The *Tri-States NGL Pipeline* transports mixed NGLs from Mobile Bay, Alabama to points near Kenner, Louisiana.

- The *Texas Express Gathering System* is comprised of two gathering systems that deliver mixed NGLs to the Texas Express Pipeline. The Elk City gathering system is comprised of 55 miles of pipeline and gathers mixed NGLs from natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle. The North Texas gathering system comprises 61 miles of pipeline and gathers mixed NGLs from natural gas processing plants in the Barnett Shale production area in North Texas.

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

NGL fractionation
We own or have interests in 14 NGL fractionators, located in Texas and Louisiana, which separate mixed NGL streams into purity NGL products for third party customers and also our NGL marketing activities. The primary sources of mixed NGLs fractionated in the U.S. are domestic natural gas processing plants, crude oil refineries and imports of butane and propane mixtures. Mixed NGLs sourced from domestic natural gas processing plants and crude oil refineries are typically transported to NGL fractionation facilities by NGL pipelines and, to a lesser extent, by railcar and truck.

Mixed NGLs extracted by domestic natural gas processing plants represent the largest source of volumes processed by our NGL fractionators. Based upon industry data, we believe that sufficient volumes of mixed NGLs, especially those originating from natural gas processing plants located in West Texas, along the Gulf Coast and in the Rocky Mountains and Mid-Continent regions, will be available for fractionation in commercially viable quantities for the foreseeable future. Significant volumes of mixed NGLs are contractually committed to be processed at our NGL fractionators by joint owners and third party customers.

The results of operations of our NGL fractionation business are generally dependent upon the volume of mixed NGLs fractionated and either the level of fractionation fees charged (under fee-based contracts) or the value of NGLs received (under percent-of-liquids arrangements). Our fee-based fractionation customers retain title to the NGLs that we process for them. To the extent we fractionate volumes for customers under percent-of-liquids contracts, we are exposed to fluctuations in NGL prices (i.e., commodity price risk). We attempt to mitigate these risks through the use of commodity derivative instruments such as forward sales contracts.

The following table presents selected information regarding our primary NGL fractionation facilities at February 1, 2018:

Description of Asset	Location	Our Ownership Interest	Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
NGL fractionation facilities:				
Mont Belvieu	Texas	Various (2)	572	670
Shoup and Armstrong	Texas	100.0%	93	93
Hobbs	Texas	100.0%	75	75
Norco	Louisiana	100.0%	75	75
Promix	Louisiana	50.0% (3)	73	145
Baton Rouge	Louisiana	32.2% (4)	19	60
Total			907	1,118

(1) The approximate net plant capacity does not necessarily correspond to our ownership interest in each facility. The capacity is based on a variety of factors such as the level of volumes an owner processes at the facility and contractual arrangements with joint owners.
(2) Six of our eight Mont Belvieu NGL fractionators are held jointly with third parties. We proportionately consolidate a 75% undivided interest in three units and substantially all of a fourth unit. We own a 75% consolidated equity interest in NGL fractionators VII and VIII through our majority owned subsidiary, Enterprise EF78 LLC. The remaining two units, NGL fractionators V and VI, are wholly owned by us.
(3) Our ownership interest in the Promix fractionator is held indirectly through our equity method investment in Promix.
(4) Our ownership interest in the Baton Rouge fractionator is held indirectly through our equity method investment in Baton Rouge Fractionators LLC ("BRF").

On a weighted-average basis, overall utilization rates for our NGL fractionators were 91.0%, 90.2% and 90.1% during the years ended December 31, 2017, 2016 and 2015, respectively. We operate all of our NGL fractionators. The following information describes each of our principal NGL fractionators:

- Our *Mont Belvieu* NGL fractionation complex is located at Mont Belvieu, Texas, which is a key hub of the global NGL industry. Our Mont Belvieu NGL fractionation assets process mixed NGLs from several major NGL supply basins in North America, including the Eagle Ford Shale, Rocky Mountains, Mid-Continent, Permian Basin and San Juan Basin. Our Mont Belvieu NGL fractionation complex features connectivity to our network of NGL supply and distribution pipelines, approximately 130 MMBbls of salt dome storage capacity, and access to international markets through our existing LPG export facility and ethane export facility.

  In March 2017, we resumed construction of our ninth NGL fractionator at Mont Belvieu in anticipation of increased NGL production from the Permian Basin. The new fractionator, which is expected to be completed by mid-2018, would have a nameplate capacity of 85 MBPD. Upon completion of this expansion project, we would have approximately 755 MBPD of total NGL fractionation capacity at our Mont Belvieu complex.

- Our *Shoup* and *Armstrong* NGL fractionators process mixed NGLs supplied by our South Texas natural gas processing plants. Purity NGL products from the Shoup and Armstrong fractionators are transported to local markets in the Corpus Christi area and also to Mont Belvieu, Texas using our South Texas NGL Pipeline System.

- Our *Hobbs* NGL fractionator serves NGL producers in West Texas, New Mexico and Colorado. The Hobbs fractionator receives mixed NGLs from several major supply basins, including the Mid-Continent, Permian Basin, San Juan Basin and Rocky Mountains. The facility is located at the interconnect of our Mid-America Pipeline System and Seminole Pipeline, thus providing us the operating flexibility to supply both the nation's largest NGL hub at Mont Belvieu as well as access to the second-largest NGL hub at Conway, Kansas.

- Our *Norco* NGL fractionator receives mixed NGLs via pipeline from refineries and natural gas processing plants located in southern Louisiana and along the Mississippi and Alabama Gulf Coast, including our Pascagoula, Venice and Toca facilities.

- The *Promix* NGL fractionator receives mixed NGLs via pipeline from natural gas processing plants located in southern Louisiana and along the Mississippi Gulf Coast, including our Neptune and Pascagoula facilities. In addition to the Promix NGL Gathering System, Promix owns three NGL storage caverns and leases a fourth NGL storage cavern. Promix also owns a barge loading facility.

- The *Baton Rouge* NGL fractionator receives mixed NGLs from natural gas processing plants located in Alabama, Mississippi and southern Louisiana. This facility includes a leased NGL storage cavern.

NGL and related product storage facilities
We utilize underground storage caverns and above ground storage tanks to store mixed and purity NGLs, petrochemical and related products owned by us and our customers. The results of operations from our storage facilities are dependent upon the level of storage capacity reserved by customers, the volume of product delivered into and withdrawn from storage and the level of associated fees we charge. The following table presents selected information regarding our NGL and related product storage assets at February 1, 2018:

Storage Capacity by State	**Net Usable Storage Capacity (MMBbls)**
Texas	145.2
Louisiana	15.4
Kansas	5.8
Mississippi	5.1
Others (1)	6.8
Total (2)	178.3

(1) Includes storage capacity at facilities in Alabama, Arizona, Georgia, Illinois, Indiana, Iowa, Minnesota, Missouri, Nebraska, New York, North Carolina, Ohio, Pennsylvania, South Carolina and Wisconsin.
(2) Our aggregate net usable storage capacity includes 15.2 MMBbls held under long-term operating leases at facilities located in Indiana, Kansas, Louisiana and Texas. Approximately 2.2 MMBbls of our net usable storage capacity in Louisiana is held indirectly through our equity method investment in Promix. The remainder of our NGL underground storage caverns and above ground storage tanks are wholly owned.

We operate these facilities, with the exception of certain Louisiana storage locations, the leased Markham facility in Texas and another leased facility in Kansas. Our largest underground storage facility is located in Mont Belvieu, Texas. This facility consists of 37 underground storage caverns used to store and redeliver mixed NGLs and NGL purity, petrochemical and related products for industrial customers located along the upper Texas Gulf Coast. This facility has an aggregate usable storage capacity of approximately 130 MMBbls, a brine system with approximately 31 MMBbls of above-ground brine storage pit capacity and four wells available for brine production.

NGL export terminals and related operations
We own and operate marine export and import terminals for NGLs. The results of operations of these facilities, all of which are located on the Houston Ship Channel, are primarily dependent upon the level of volumes handled and the associated loading/unloading fees we charge for such services.

Enterprise Hydrocarbons Terminal
We own and operate a marine terminal facility, the Enterprise Hydrocarbons Terminal (or "EHT"), located on the Houston Ship Channel that provides terminaling services to major integrated oil companies, exporters, marketers, distributors and chemical companies. EHT has extensive waterfront access consisting of seven deep-water ship docks and two barge docks. The terminal can accommodate vessels with up to a 45 foot draft, including Suezmax tankers, which are the largest tankers that can navigate the Houston Ship Channel. We believe that our location on the Houston Ship Channel to the east of the Beltway 8 bridge enables us to handle larger vessels than our competitors who are located to the west of the Beltway 8 bridge because our waterfront has fewer draft and beam (width) restrictions. The size and structure of our waterfront at the Houston facility allows us not only to receive and unload products for our customers, but also to provide third party docking services for which we receive throughput fees.

EHT's facilities include those that can load cargoes of fully refrigerated, low-ethane propane and/or butane (collectively referred to as LPG) onto multiple tanker vessels simultaneously. Currently, EHT's loading rate for LPG (its nameplate capacity) is approximately 27,500 barrels per hour. Our LPG export services continue to benefit from increased NGL supplies produced from domestic shale plays such as the Permian Basin and Eagle Ford Shale and international demand for propane as a feedstock in ethylene plant operations and for power generation and heating purposes. On average, LPG loading volumes at EHT were 424 MBPD, 420 MBPD and 299 MBPD during the years ended December 31, 2017, 2016 and 2015, respectively.

The primary customer of EHT is our NGL marketing group, which uses EHT to meet the needs of export customers. NGL marketing transacts with these customers using long-term sales contracts with take-or-pay provisions and/or exchange agreements. In recent years, the U.S. has become the largest exporter of LPG in the world, with shipments originating from EHT playing a key role. Of the LPG cargoes we loaded for export at EHT during the year ended December 31, 2017, the destination markets were as follows: 56% to Asia; 20% to Central and South America; 14% to North America and the Caribbean; 9% to Europe and Africa; and 1% to other destinations, including Australia and the Middle East. Based on available information, our LPG sales to export customers represented the following percentage of each destination market's approximate total supply: 57% for Central and South America; 43% for Asia; 40% for North America and the Caribbean; 27% for Europe and Africa; and 23% for other destinations, including Australia and the Middle East.

We also own and operate an NGL import terminal located at the EHT facility. This import terminal can offload NGLs from tanker vessels at rates up to 14,000 barrels per hour depending on the product. Our NGL import volumes for the last three years were minimal.

EHT also provides terminaling services involving crude oil, petrochemicals and refined products. EHT's assets and activities involving crude oil terminaling and storage are classified and presented as a component of our Crude Oil Pipelines & Services business segment. EHT's activities involving petrochemical and refined products customers are classified and described within our Petrochemical & Refined Products Services business segment.

Morgan's Point Ethane Export Terminal
In September 2016, we placed our Morgan's Point Ethane Export Terminal, which is located on the Houston Ship Channel, into commercial service. The terminal has an aggregate loading rate (nameplate capacity) of approximately 10,000 barrels per hour of fully refrigerated ethane and is the largest of its kind in the world. Ethane volumes handled by the terminal are sourced from our Mont Belvieu NGL fractionation and storage complex. The terminal is supported by customer volume commitments that increase to over 180 MBPD within the next three years (depending on customer elections).

The Morgan's Point Ethane Export Terminal supports growing international demand for abundant U.S. ethane from shale plays, which offers the global petrochemical industry a low-cost feedstock option and supply diversification. We estimate that U.S. ethane production capacity currently exceeds U.S. demand by 500 to 600 MBPD and could exceed demand by up to 350 MBPD in 2020, after considering the estimated incremental demand from new third party ethylene facilities that are being constructed on the Gulf Coast. By providing producers with access to the export market, the Morgan's Point Ethane Export Terminal supports continued development of U.S. energy reserves.

Crude Oil Pipelines & Services Segment

Our Crude Oil Pipelines & Services business segment includes approximately 5,800 miles of crude oil pipelines, crude oil storage and marine terminals, and associated crude oil marketing activities.

Crude oil pipelines
We have crude oil gathering and transportation pipelines located in Oklahoma, New Mexico and Texas. The results of operations from providing crude oil transportation services is primarily dependent upon the volume handled (or capacity reserved) and the level of fees charged (typically on a per barrel basis). Fees charged to shippers are based on either tariffs regulated by governmental agencies, including the FERC, or contractual arrangements. See "Regulatory Matters" within this Part I, Item 1 and 2 discussion for additional information regarding governmental oversight of crude oil pipelines.

The following table presents selected information regarding our crude oil pipelines and related operations at February 1, 2018:

Description of Asset	Location(s)	Our Ownership Interest	Pipeline Length (Miles)
Crude oil pipelines:			
Seaway Pipeline (1)	Texas, Oklahoma	50.0% (2)	1,273
Red River System (1)	Texas, Oklahoma	100.0%	1,129
West Texas System (1)	Texas, New Mexico	100.0%	862
South Texas Crude Oil Pipeline System	Texas	100.0%	647
Basin Pipeline (1)	Texas, New Mexico, Oklahoma	13.0% (3)	607
EFS Midstream System	Texas	100.0%	471
Midland-to-ECHO Pipeline System	Texas	100.0%	416
Eagle Ford Crude Oil Pipeline System	Texas	50.0% (4)	378
Total			5,783

(1) Transportation services provided by these liquids pipelines are regulated, in whole or part, by federal governmental agencies.
(2) Our ownership interest in the Seaway Pipeline is held indirectly through our equity method investment in Seaway Crude Pipeline Company LLC ("Seaway").
(3) We proportionately consolidate our undivided interest in the Basin Pipeline.
(4) Our ownership interest in the Eagle Ford Crude Oil Pipeline System is held indirectly through our equity method investment in Eagle Ford Pipeline LLC.

The maximum number of barrels per day that our crude oil pipelines can transport depends on the operating rates achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and grades of crude oil being transported). As a result, we measure the utilization rates of our crude oil pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 1,820 MBPD, 1,388 MBPD and 1,474 MBPD during the years ended December 31, 2017, 2016 and 2015, respectively.

The following information describes each of our principal crude oil pipelines, all of which we operate with the exception of the Basin Pipeline and Eagle Ford Crude Oil Pipeline System.

- The *Seaway Pipeline* connects the Cushing, Oklahoma crude oil hub with markets in southeast Texas. The Seaway Pipeline is comprised of the Longhaul System, the Freeport System and the Texas City System. The Cushing hub is a major industry trading hub and price settlement point for West Texas Intermediate ("WTI") crude oil on the New York Mercantile Exchange ("NYMEX").

  The Longhaul System consists of two 500-mile, 30-inch diameter pipelines that provide north-to-south transportation of crude oil from the Cushing hub to Seaway's Jones Creek terminal located near Freeport, Texas and a terminal that we own located near Katy, Texas. The second of these two pipelines, which was placed into commercial service in December 2014, is referred to as the "Seaway Loop." The aggregate transportation capacity of the Longhaul System is approximately 850 MBPD, depending on the type and mix of crude oil being transported and other variables.

  The Freeport System consists of two marine ship docks and one barge dock to facilitate imports and exports, three pipelines and other related facilities that transport crude oil to and from Freeport, Texas and the Jones Creek terminal. The Texas City System consists of two marine ship docks that facilitate imports and exports, and storage tanks, various pipelines and related facilities that transport crude oil to refineries in the Texas City, Texas area and to and from terminals in the Galena Park, Texas area, our Enterprise Crude Houston ("ECHO") terminal and locations along the Houston Ship Channel. The Texas City System also receives production from certain offshore Gulf of Mexico developments. The intrastate transportation capacity of the Freeport System and Texas City System is approximately 480 MBPD and 800 MBPD, respectively.

In total, the Seaway Pipeline includes 21 storage tanks located along the Texas Gulf Coast having a combined 9.6 MMBbls of operational crude oil storage tank capacity (4.8 MMBbls net to our ownership interest). This includes four storage tanks that are located at our ECHO terminal, two of which are owned by Seaway and two that we lease to Seaway.

- The *Red River System* gathers and transports crude oil from North Texas and southern Oklahoma for delivery to local refineries and pipeline interconnects for further transportation to the Cushing hub. The Red River System includes 1.1 MMBbls of operational crude oil storage capacity.

- The *West Texas System* connects crude oil gathering systems in West Texas and southeast New Mexico to our terminal facility in Midland, Texas. The West Texas System includes 0.6 MMBbls of operational crude oil storage capacity.

- The *South Texas Crude Oil Pipeline System* transports crude oil and condensate originating in South Texas to the Greater Houston area. The system includes 3.6 MMBbls of operational crude oil storage capacity, including 1.8 MMBbls located in Sealy, Texas. The South Texas Crude Oil Pipeline System also includes our Rancho II pipeline, which extends 89-miles from Sealy, Texas to our ECHO terminal. From ECHO, we have connectivity to refineries and downstream assets including our export dock facilities.

- The *Basin Pipeline* transports crude oil from the Permian Basin in West Texas and southern New Mexico to the Cushing hub. The Basin Pipeline includes approximately 6 MMBbls of operational crude oil storage capacity (0.8 MMBbls net to our ownership interest).

- The *EFS Midstream System* serves producers in the Eagle Ford Shale, providing condensate gathering and processing services as well as gathering, treating and compression services for associated natural gas. The EFS Midstream System includes 471 miles of gathering pipelines, 11 central gathering plants having a combined condensate storage capacity of 0.3 MMBbls, 171 MBPD of condensate stabilization capacity and 1.0 Bcf/d of associated natural gas treating capacity.

  We acquired the EFS Midstream System in July 2015. For information regarding this acquisition, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

- The *Midland-to-ECHO Pipeline System* transports crude oil and condensate from the Permian Basin to markets in southeast Texas. This new 24-inch diameter pipeline, which is expected to be fully operational in the second quarter of 2018, has a design capacity of 450 MBPD. The pipeline originates at our Midland, Texas crude oil terminal and extends 416 miles to our Sealy, Texas storage 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. When fully completed in 2018, the Midland-to-ECHO Pipeline System will include 3.8 MMBbls of operational crude oil storage capacity. Using the ECHO terminal, shippers on the Midland-to-ECHO Pipeline System have access to every refinery in Houston, Texas City, Beaumont and Port Arthur, Texas, as well as our crude oil export dock facilities. In November 2017, we began limited service on our Midland-to-ECHO pipeline by moving a single grade of crude oil from the Permian Basin to the Houston refining and export market.

- The *Eagle Ford Crude Oil Pipeline System* transports crude oil and condensate for producers in South Texas. The system, which is effectively looped and has a capacity to transport over 600 MBPD of light and medium grades of crude oil, consists of 378 miles of crude oil and condensate pipelines originating in Gardendale, Texas and extending to Corpus Christi, Texas. The system also interconnects with our South Texas Crude Oil Pipeline System in Wilson County, Texas. The Eagle Ford Crude Oil Pipeline System includes an aggregate 4.5 MMBbls of operational storage capacity across its system (2.2 MMBbls net to our ownership interest) and a marine barge terminal in Corpus Christi.

  In addition, we are joint owners of a new deep-water marine crude oil terminal that is being constructed in Corpus Christi that is designed to handle a variety of ocean-going vessels. The new terminal is expected to be placed into service during the third quarter of 2018.

Crude oil terminals

In addition to the operational storage capacity associated with our crude oil pipelines, we also own and operate crude oil terminals located in Houston, Midland and Beaumont, Texas and Cushing, Oklahoma that are used to store crude oil for us and our customers. In conjunction with other aspects of our midstream network, our crude oil terminals provide Gulf Coast refiners with an integrated system featuring supply diversification, significant storage capabilities and a high capacity pipeline distribution system that is connected to customers having an aggregate refining capacity of approximately 4.4 MMBPD.

The results of operations from crude oil terminal storage services are primarily dependent upon the level of volumes stored and the length of time such storage occurs, including the level of firm storage capacity reserved, pumpover volumes and the fees associated with each activity. If the terminal offers marine services, the results of operations from these activities are primarily dependent upon the level of volumes handled and the associated loading/unloading fees we charge for such services.

The following table presents selected information regarding our crude oil terminals at February 1, 2018:

Description of Asset	Location(s)	Our Ownership Interest	Storage Capacity (MMBbls)
Crude oil terminals:			
EHT crude oil storage facility	Texas	100.0%	21.3
ECHO terminal	Texas	100.0%	5.6
Beaumont Marine West Crude Oil terminal	Texas	100.0%	4.1
Cushing terminal	Oklahoma	100.0%	3.5
Midland terminal	Texas	100.0%	2.5
Morgan's Point terminal	Texas	100.0%	0.1
Total			37.1

The following information describes each of our principal crude oil terminals, all of which we operate.

- The *EHT crude oil storage facility* is one of the largest such facilities on the Gulf Coast with 21.3 MMBbls of aggregate crude oil storage capacity through the use of 77 above-ground storage tanks. This storage facility is part of our EHT complex, which has extensive waterfront access consisting of seven deep-water ship docks and two barge docks.

- The *ECHO terminal* is located in Houston, Texas and provides storage customers with access to major refineries located in the Houston, Texas City and Beaumont/Port Arthur areas. The ECHO terminal also has connections to marine terminals, including our EHT crude oil terminal, that provide access to any refinery on the U.S. Gulf Coast. Excluding four tanks aggregating 1.8 MMBbls of storage capacity owned or leased by Seaway, the ECHO terminal has 5.6 MMBbls of aggregate storage capacity through the use of 13 above-ground storage tanks.

- The *Beaumont Marine West Crude Oil terminal* is a marine terminal complex located on the Neches River near Beaumont, Texas. This complex has an aggregate crude oil storage capacity of 4.1 MMBbls through the use of 12 above-ground storage tanks. In addition, this terminal includes four deep-water docks and two barge docks to facilitate the exporting and importing of crude oil and related products.

- The *Cushing terminal* provides crude oil storage, pumpover and trade documentation services. Our terminal in Cushing, Oklahoma has an aggregate storage capacity of 3.5 MMBbls through the use of 20 above-ground storage tanks.

- The *Midland terminal* provides crude oil storage, pumpover and trade documentation services. The Midland, Texas terminal has an aggregate storage capacity of 2.5 MMBbls through the use of 12 above-ground storage tanks.

Crude oil marketing activities
Our crude oil marketing activities generate revenues from the sale and delivery of crude oil and condensate purchased either directly from producers or from others on the open market. The results of operations from our crude oil marketing activities are primarily dependent upon the difference, or spread, between crude oil and condensate sales prices and the associated purchase and other costs, including those costs attributable to the use of our other assets. In general, sales prices referenced in the underlying contracts are market-based and include pricing differentials for factors such as delivery location or crude oil quality. We also use derivative instruments to mitigate our exposure to commodity price risks associated with our crude oil marketing activities. For a discussion of our commodity hedging program, see Part II, Item 7A of this annual report.

Our Crude Oil Pipelines & Services segment also includes a fleet of approximately 495 tractor-trailer tank trucks, the majority of which we lease and operate, that are used to transport crude oil.

Natural Gas Pipelines & Services Segment

Our Natural Gas Pipelines & Services business segment includes approximately 19,700 miles of natural gas pipeline systems that provide for the gathering and transportation of natural gas in Colorado, Louisiana, New Mexico, Texas and Wyoming. This segment also includes our natural gas marketing activities.

Natural gas pipelines and related storage assets
Our natural gas pipeline systems gather and transport natural gas from producing regions such as the Permian, Eagle Ford Shale, Haynesville Shale, and the Piceance, San Juan and Greater Green River supply basins. In addition, certain of these pipelines receive natural gas production from Gulf of Mexico developments through coastal pipeline interconnects with third party offshore pipelines. Our natural gas pipelines redeliver the natural gas to processing facilities, electric generation plants, local gas distribution companies, industrial or municipal customers, storage facilities or other onshore pipelines.

The results of operations from our natural gas pipelines and related storage assets are primarily dependent upon the volume of natural gas transported or stored, the level of firm capacity reservations made by shippers, and the associated fees we charge for such activities. Transportation fees charged to shippers (typically per MMBtu of natural gas) are based on either tariffs regulated by governmental agencies, including the FERC, or contractual arrangements. See "Regulatory Matters" within this Part I, Item 1 and 2 discussion for additional information regarding governmental oversight of natural gas pipelines.

The following table presents selected information regarding our natural gas pipelines and related storage assets at February 1, 2018:

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Approximate Net Capacity: Pipelines (MMcf/d)	Approximate Net Capacity: Usable Storage (Bcf)
Natural gas pipelines and storage:					
Texas Intrastate System (1)	Texas	Various (4)	7,261	6,295	12.9
Acadian Gas System (1)	Louisiana	100.0% (5)	1,317	3,100	1.3
Jonah Gathering System	Wyoming	100.0%	761	2,360	--
Piceance Basin Gathering System	Colorado	100.0%	190	1,800	--
San Juan Gathering System	New Mexico, Colorado	100.0%	6,119	1,750	--
White River Hub (2)	Colorado	50.0% (6)	10	1,500	--
Haynesville Gathering System	Louisiana, Texas	100.0%	357	1,300	--
BTA Gathering System(3)	Texas	100.0%	753	1,000	--
Permian Basin Gathering System	Texas, New Mexico	100.0%	1,553	505	--
Fairplay Gathering System (3)	Texas	100.0% (7)	272	285	--
Indian Springs Gathering System (3)	Texas	80.0% (8)	148	160	--
Delmita Gathering System	Texas	100.0%	204	145	--
South Texas Gathering System	Texas	100.0%	518	143	--
Big Thicket Gathering System	Texas	100.0%	249	60	--
Total			19,712		14.2

(1) Transportation services provided by these pipeline systems, in whole or part, are regulated by both federal and state governmental agencies.
(2) Services provided by the White River Hub are regulated by federal governmental agencies.
(3) Transportation services provided by these systems are regulated in part by state governmental agencies.
(4) Of the 7,261 miles comprising the Texas Intrastate System, we lease 240 miles from a third party. We proportionately consolidate our undivided interests, which range from 22% to 80%, in 1,471 miles of pipeline. Our Wilson natural gas storage facility consists of five underground salt dome natural gas storage caverns with 12.9 Bcf of usable storage capacity, four of which (comprising 6.9 Bcf of usable capacity) are held under an operating lease that expires in January 2028. The remainder of our Texas Intrastate System is wholly owned.
(5) The Acadian Gas System is wholly owned except for an underground salt dome natural gas storage facility held under an operating lease that expires in December 2018.
(6) Our ownership interest in the White River Hub facility is held indirectly through our equity method investment in White River Hub, LLC ("White River Hub").
(7) The Fairplay Gathering System includes approximately 52 miles of pipeline held under an operating lease.
(8) We proportionately consolidate our 80% undivided interest in the Indian Springs Gathering System.

On a weighted-average basis, overall utilization rates for our natural gas pipelines were approximately 57.1%, 57.4% and 59.3% during the years ended December 31, 2017, 2016 and 2015, respectively. These utilization rates represent actual natural gas volumes delivered as a percentage of our nominal delivery capacity and do not reflect firm capacity reservation agreements where capacity fees are earned whether or not the shipper actually utilizes such capacity.

The following information describes each of our principal natural gas pipelines. With the exception of the White River Hub and certain segments of the Texas Intrastate System, we operate our natural gas pipelines and storage facilities.

- The *Texas Intrastate System* is comprised of the 6,634-mile Enterprise Texas pipeline system and the 627-mile Channel pipeline system. The Texas Intrastate System gathers, transports and stores natural gas from supply basins in Texas such as the Permian Basin and Eagle Ford and Barnett Shales for redelivery to local gas distribution companies and electric generation, industrial and municipal consumers as well as to connections with other intrastate and interstate pipelines. The Texas Intrastate System serves various commercial markets in Texas, including Corpus Christi, San Antonio/Austin, Beaumont/Orange and Houston, including the Houston Ship Channel industrial market. The Wilson natural gas storage facility, which is an important part of the Texas Intrastate System, is comprised of a network of leased and owned underground salt dome storage caverns located in Wharton County, Texas.

- The *Acadian Gas System* transports, stores and markets natural gas in Louisiana. The Acadian Gas System is comprised of the 589-mile Cypress pipeline, 427-mile Acadian pipeline, 275-mile Haynesville Extension pipeline and 26-mile Enterprise Pelican pipeline. The Acadian Gas System includes a leased underground salt dome natural gas storage cavern located at Napoleonville, Louisiana. The Acadian Gas System links natural gas supplies from Louisiana (e.g., from Haynesville Shale supply basin) and offshore Gulf of Mexico developments with local gas distribution companies, electric generation plants and industrial customers located primarily in the Baton Rouge/New Orleans/Mississippi River corridor.

- The *Jonah Gathering System* is located in the Greater Green River Basin of southwest Wyoming. This system gathers natural gas from the Jonah and Pinedale supply fields for delivery to regional natural gas processing plants, including our Pioneer facilities, for ultimate delivery into major interstate pipelines.

- The *Piceance Basin Gathering System* consists of a network of gathering pipelines located in the Piceance Basin of northwestern Colorado. The Piceance Basin Gathering System gathers natural gas throughout the Piceance Basin to our Meeker natural gas processing complex for ultimate delivery into the White River Hub and other major interstate pipelines.

- The *San Juan Gathering System* serves producers in the San Juan Basin of northern New Mexico and southern Colorado. This system gathers natural gas from production wells located in the San Juan Basin and delivers the natural gas either directly into major interstate pipelines or to regional processing and treating plants, including our Chaco processing facility and Val Verde treating plant located in New Mexico, for ultimate delivery into major interstate pipelines.

- The *White River Hub* is a natural gas hub facility serving producers in the Piceance Basin of northwest Colorado. The facility enables producers to access six interstate natural gas pipelines and has a gross throughput capacity of 3 Bcf/d of natural gas (1.5 Bcf/d net to our interest).

- The *Haynesville Gathering System* consists of the 214-mile State Line gathering system, the 73-mile Southeast Mansfield gathering system, the 70-mile Southeast Stanley gathering system and three natural gas treating plants. The Haynesville Gathering System gathers natural gas produced from the Haynesville and Bossier Shale supply basins and the Cotton Valley and Taylor Sand formations in Louisiana and eastern Texas for delivery to regional markets, including (through an interconnect with the Haynesville Extension pipeline) markets served by our Acadian Gas System.

- The *BTA Gathering System* gathers natural gas from the Haynesville Shale and Bossier, Cotton Valley and Travis Peak formations. We acquired this system in April 2017 from Azure Midstream Partners, LP and its operating subsidiaries (collectively, "Azure") for $191.4 million in cash. The acquired business assets, which are located primarily in East Texas, include 753 miles of natural gas gathering pipelines and two natural gas processing plants (Panola and Fairway, which are part of our NGL Pipelines & Services segment). For information regarding this acquisition, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

- The *Permian Basin Gathering System* is comprised of the 973-mile Carlsbad pipeline system and 580-mile Waha pipeline system. The Permian Basin Gathering System gathers natural gas from the Permian Basin region of Texas and New Mexico for delivery to natural gas processing plants, including our Chaparral, Carlsbad, South Eddy and Waha plants, and delivers processed natural gas into the El Paso Natural Gas and Transwestern pipelines and our Texas Intrastate System.

- The *Fairplay Gathering System* gathers natural gas produced from the Cotton Valley formation within Panola and Rusk Counties in East Texas for delivery to regional markets.

In addition to our natural gas pipelines, we own and operate a natural gas treating facility (the "Central Treating Facility") located in Rio Blanco County, Colorado. This facility can treat up to 200 MMcf/d of natural gas and serves producing properties in the Piceance Basin. Natural gas delivered to the Central Treating Facility is treated to remove impurities and transported to our Meeker gas plant for further processing.

Natural gas marketing activities
Our natural gas marketing activities generate revenues from the sale and delivery of natural gas purchased from producers, regional natural gas processing plants and on the open market. Our natural gas marketing customers include local gas distribution companies and electric generation plants. The results of operations from our natural gas marketing activities are primarily dependent upon the difference, or spread, between natural gas sales prices and the associated purchase and other costs, including those costs attributable to the use of our other assets. In general, sales prices referenced in the underlying contracts are market-based and may include pricing differentials for factors such as delivery location.

We are exposed to commodity price risk to the extent that we take title to natural gas volumes in connection with our natural gas marketing activities and certain intrastate natural gas transportation contracts. In addition, we purchase and resell natural gas for certain producers that use our San Juan, Piceance, Permian Basin and Jonah Gathering Systems and certain segments of our Acadian Gas and Texas Intrastate Systems. Also, several of our natural gas gathering systems, while not providing marketing services, have some exposure to risks related to fluctuations in commodity prices through transportation arrangements with shippers. For example, nearly all of the transportation revenues generated by our San Juan Gathering System are based on a percentage of a regional natural gas price index. This index may fluctuate based on a variety of factors, including changes in natural gas supply and consumer demand. We attempt to mitigate these price risks through the use of commodity derivative instruments. For a discussion of our commodity hedging program, see Part II, Item 7A of this annual report.

Petrochemical & Refined Products Services Segment

Our Petrochemical & Refined Products Services business segment includes: (i) propylene production facilities, which include our propylene fractionation units and recently completed propane dehydrogenation ("PDH") facility, approximately 800 miles of pipelines, and associated marketing operations; (ii) a butane isomerization complex and related deisobutanizer ("DIB") operations; (iii) octane enhancement and high purity isobutylene ("HPIB") production facilities; (iv) refined products pipelines aggregating approximately 4,100 miles, terminals and associated marketing activities; and (v) marine transportation.

Propylene production and related operations
This business area consists of seven propylene fractionation (or splitter) units, our recently constructed PDH facility, 795 miles of related pipelines, and associated marketing activities. With the exception of the Lake Charles PGP Pipeline in Louisiana, we operate all of our propylene production assets and related pipelines.

Propylene is a key feedstock used by the petrochemical industry. There are three grades of propylene; polymer grade ("PGP") with a minimum purity of 99.5%; chemical grade ("CGP") with a minimum purity of approximately 93-94%; and refinery grade ("RGP") with a purity of approximately 70%. In 2017, the global demand for propylene (PGP and CGP combined) was estimated at 104 million tons. The PDH facility produces PGP using propane feedstocks. Propylene fractionation units separate RGP, which is a mixture of propane and propylene, into either PGP or CGP. The demand for PGP primarily relates to the manufacture of polypropylene, which has a variety of end uses including packaging film, fiber for carpets and upholstery and molded plastic parts for appliances and automotive, houseware and medical products. CGP is a basic petrochemical used in the manufacturing of plastics, synthetic fibers and foams.

Our recently constructed PDH facility at Mont Belvieu has the capacity to produce up to 1.65 billion pounds per year, or approximately 25 MBPD, of PGP. At this nameplate production rate, the facility is expected to consume approximately 35 MBPD of propane as feedstock. The PDH facility is integrated with our legacy Mont Belvieu propylene fractionation units, which provides us with operational reliability and flexibility for both the PDH facility and the fractionation units. The facility's construction is underwritten by long-term fee-based contracts that feature minimum volume commitments. We expect the PDH facility to enter full service during the first quarter of 2018.

We have initiated legal proceedings involving the former general contractor for the PDH facility. For a summary of this litigation, see Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

The results of operations from our propylene fractionation units are generally dependent upon toll processing arrangements with customers. The results of operations from our petrochemical pipelines are primarily dependent upon the volume of products transported and the level of fees charged to shippers.

We purchase RGP on the open market for fractionation at our facilities and sell the resulting PGP at market-based prices. The results of operations from these petrochemical marketing activities are primarily dependent upon the difference, or spread, between the sales prices of the products and associated purchase and other costs, including those costs attributable to the use of our assets. To limit the exposure of these marketing activities to price risk, we attempt to match the timing and price of our feedstock purchases with those of the sales of end products.

Our petrochemical marketing activities also include the results of operations of our PDH facility. We purchase propane for our PDH facility to process into PGP, which is then sold to customers under long-term sales contracts (take-or-pay arrangements) that feature minimum volume commitments and contractual pricing that minimizes our commodity price risk.

In order to meet the demand of international customers, this business also includes export assets located at our EHT complex that are capable of loading up to 5,000 metric tons per day of refrigerated PGP.

The following table presents selected information regarding our propylene fractionation units at February 1, 2018:

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)
Propylene fractionation facilities:				
Mont Belvieu (six units)	Texas	Various (1)	81	95
BRPC (one unit)	Louisiana	30.0% (2)	7	23
Total			88	118

(1) We proportionately consolidate a 66.7% undivided interest in three of the propylene fractionation units, which have an aggregate 41 MBPD of total plant capacity. The remaining three propylene fractionation units are wholly owned.
(2) Our ownership interest in the BRPC facility is held indirectly through our equity method investment in Baton Rouge Propylene Concentrator LLC ("BRPC").

We produce PGP at our Mont Belvieu, Texas propylene fractionation units and CGP at our BRPC facility located in Baton Rouge, Louisiana. On a weighted-average basis, the overall utilization rate of our propylene fractionation facilities was approximately 89.9%, 81.9% and 80.5% during the years ended December 31, 2017, 2016 and 2015, respectively.

The following table presents selected information regarding our propylene pipelines at February 1, 2018:

Description of Asset	Location(s)	Ownership Interest	Length (Miles)
Petrochemical pipelines:			
Lou-Tex Propylene Pipeline	Texas, Louisiana	100.0%	263
Texas City RGP Gathering System	Texas	100.0%	168
North Dean Pipeline System	Texas	100.0%	157
Propylene Splitter PGP Distribution System	Texas	100.0%	82
Sorrento-to-Breaux Bridge RGP Pipeline	Louisiana	100.0%	63
Lake Charles PGP Pipeline	Texas, Louisiana	50.0% (1)	27
La Porte PGP Pipeline	Texas	80.0% (2)	20
Sabine Pipeline	Texas, Louisiana	100.0%	15
Total			795

(1) We proportionately consolidate our undivided interest in the Lake Charles PGP Pipeline.
(2) We own an 80% consolidated interest in the La Porte PGP Pipeline through our majority owned subsidiaries, La Porte Pipeline Company, L.P. and La Porte Pipeline GP, L.L.C.

The maximum number of barrels per day that our petrochemical pipelines can transport depends on the operating rates achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and the mix of products being transported). As a result, we measure the utilization rates of our petrochemical pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes were 106 MBPD, 121 MBPD and 126 MBPD during the years ended December 31, 2017, 2016 and 2015, respectively.

The Lou-Tex Propylene pipeline is used to transport CGP from Sorrento, Louisiana to Mont Belvieu, Texas. In June 2015, we announced plans to convert the Lou-Tex Propylene pipeline from CGP to PGP service. This conversion is scheduled for completion in 2020.

In June 2015, we announced plans for the construction of a 63-mile, 10-inch diameter pipeline that would transport RGP between Sorrento and Breaux Bridge, Louisiana. The Sorrento-to-Breaux Bridge RGP Pipeline was completed and placed into service in the fourth quarter of 2017.

Isomerization and related operations

At Mont Belvieu, Texas, we own and operate three isomerization units having an aggregate processing capacity of 116 MBPD that comprise the largest commercial isomerization facility in the U.S. These operations also include a 70-mile pipeline system used to transport high-purity isobutane from Mont Belvieu, Texas to Port Neches, Texas that we own and operate.

The demand for commercial isomerization services depends upon the energy industry's requirements for isobutane and high-purity isobutane in excess of the isobutane produced through the process of NGL fractionation and refinery operations. Isomerization units convert normal butane feedstock into mixed butane, which is a stream of isobutane and normal butane. DIB units, of which we own and operate nine located at our Mont Belvieu complex, then separate the isobutane from the normal butane. Any remaining unconverted (or residual) normal butane generated by the DIB process is then recirculated through the isomerization process until it has been converted into varying grades of isobutane, including high-purity isobutane. The primary uses of isobutane are for the production of propylene oxide, isooctane, isobutylene and alkylate for motor gasoline. We also use certain of our DIB units to fractionate mixed butanes produced from NGL fractionation activities, from imports and from other sources into isobutane and normal butane. The operating flexibility provided by our multiple standalone DIBs enables us to capture opportunities resulting from fluctuations in demand and prices for different types of butane.

The results of operations from our isomerization business are generally dependent on the volume of normal and mixed butanes processed and the level of toll processing fees charged to customers.

Our isomerization assets provide processing services to meet the needs of third party customers and our other businesses, including our NGL marketing activities and octane enhancement production facility. On a weighted-average basis, the utilization rates of our isomerization facility were approximately 92.2%, 93.1% and 82.8% during the years ended December 31, 2017, 2016 and 2015, respectively.

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.

Octane enhancement and related operations

We own and operate an octane enhancement production facility located in Mont Belvieu, Texas that is designed to produce isobutylene and either isooctane or MTBE. The products produced by this facility are used by refiners in the production of reformulated motor gasoline blends to increase octane values. The high-purity isobutane feedstocks consumed in the production of these products are supplied by our isomerization units.

We sell our octane enhancement products at market-based prices. We attempt to mitigate the price risk associated with these products by entering into commodity derivative instruments. To the extent that we produce MTBE, it is sold exclusively into the export market. We measure the utilization of our octane enhancement facility in terms of combined isooctane, isobutylene and MTBE production volumes, which averaged 23 MBPD, 19 MBPD and 15 MBPD for the years ended December 31, 2017, 2016 and 2015, respectively. Octane enhancement production volumes for 2015 were adversely impacted by extended maintenance outages.

We also own and operate a facility located on the Houston Ship Channel that produces up to 4 MBPD of HPIB and includes an associated storage facility with 0.6 MMBbls of storage capacity. The primary feedstock for this plant, an isobutane/isobutylene mix, is produced by our Mont Belvieu octane enhancement facility. HPIB is used in the formulation of polyisobutylene, which is used in the manufacture of lubricants and rubber. In general, we sell HPIB at market-based prices with a cost-based floor. On a weighted-average basis, utilization rates for this facility were 75.9%, 58.4% and 54.8% for the years ended December 31, 2017, 2016 and 2015, respectively.

The results of operations from our octane enhancement and HPIB facilities are generally dependent on the level of production volumes and the difference, or spread, between the sales prices of the products (e.g., MTBE and isobutylene) and the associated feedstock purchase costs (e.g., methanol and high-purity isobutane) and other operating expenses.

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

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

Refined products pipelines
We own and operate the TE Products Pipeline, which is a 3,317-mile pipeline system comprised of 2,992 miles of regulated interstate pipelines and 325 miles of unregulated intrastate Texas pipelines. The system primarily transports refined products from the upper Texas Gulf Coast to Seymour, Indiana. From Seymour, segments of the TE Products Pipeline extend to Chicago, Illinois; Lima, Ohio; Selkirk, New York; and a location near Philadelphia, Pennsylvania. East of Seymour, Indiana, the TE Products Pipeline is primarily dedicated to NGL transportation service. The refined products transported by the TE Products Pipeline are produced by refineries and include motor gasoline and distillates. The results of operations for this pipeline system are dependent upon the volume of products transported and the level of fees charged to shippers. The tariffs charged for such services are either contractual or regulated by governmental agencies, including the FERC.

The maximum number of barrels per day that our TE Products Pipeline can transport depends on the operating balance achieved at a given point in time between various segments of the system (e.g., demand levels at each delivery point and the mix of products being transported). As a result, we measure the utilization rate of this pipeline in terms of throughput. Aggregate throughput volumes by product type for the TE Products Pipeline were as follows for the periods presented:

	For the Year Ended December 31,		
	2017	2016	2015
Refined products transportation (MBPD)	456	474	444
Petrochemical transportation (MBPD)	156	164	144
NGL transportation (MBPD)	57	55	55

The TE Products Pipeline system includes five non-regulated refined products truck terminals and 18.5 MMBbls of refined products storage capacity. In addition, the system includes 3.7 MMBbls of NGL storage capacity, the assets of which are accounted for under our NGL Pipelines & Services business segment.

The TE Products Pipeline is subject to federal regulation. See "Regulatory Matters" within this Part I, Item 1 and 2 discussion for additional information regarding governmental oversight of liquids pipelines, including tariffs charged for transportation services.

Centennial
We own a 50% equity interest in the Centennial Pipeline, which is a 795-mile refined products pipeline that extends from Beaumont, Texas to Bourbon, Illinois. The Centennial Pipeline includes a refined products storage terminal located near Creal Springs, Illinois with a gross storage capacity of 2.3 MMBbls (1.2 MMBbls net to our ownership interest). The Centennial Pipeline is idle; however, we continue to evaluate potential projects that could repurpose the line.

Refined products marine terminals
We own and operate refined products marine terminals located on the Neches River near Beaumont, Texas that include five deep-water ship docks and three barge docks. In addition, these terminals have access to approximately 7.4 MMBbls of aggregate refined products storage capacity.

This business also includes refined products marine terminal assets at EHT, which is located on the Houston Ship Channel. In addition to providing vessel loading and unloading services for refined products, EHT's refined products operations include 2.0 MMBbls of aggregate storage capacity through the use of 24 above-ground storage tanks.

The results of operations for these marine terminals are primarily dependent upon the volume handled and the associated storage and other fees we charge.

Refined products marketing activities
Our refined products marketing activities generate revenues from the sale and delivery of refined products obtained on the open market. The results of operations from our refined products marketing activities are primarily dependent upon the difference, or spread, between product sales prices and the associated purchase and other costs, including those costs attributable to the use of our other assets. In general, we sell our refined products at market-based prices, which may include pricing differentials for factors such as grade and delivery location. We use derivative instruments to mitigate our exposure to commodity price risks associated with our refined products marketing activities. For a discussion of our commodity hedging program, see Part II, Item 7A of this annual report.

Marine transportation
Our marine transportation business consists of 61 tow boats and 138 tank barges that are used to transport refined products, crude oil, asphalt, condensate, heavy fuel oil, LPG and other petroleum products along key U.S. inland and intracoastal waterway systems. The marine transportation industry uses tow boats as power sources and tank barges for freight capacity. Our marine transportation assets serve refinery and storage terminal customers along the Mississippi River, the intracoastal waterway between Texas and Florida and the Tennessee-Tombigbee Waterway system. We own and operate shipyard and repair facilities located in Houma and Morgan City, Louisiana and marine fleeting facilities located in Bourg, Louisiana and Channelview, Texas.

The results of operations of our marine transportation business are generally dependent upon the level of fees charged (e.g., set day rates or fee per cargo movement) to transport petroleum products.

Our fleet of marine vessels operated at an average utilization rate of 86.3 %, 85.2% and 87.9% during the years ended December 31, 2017, 2016 and 2015, respectively.

Our marine transportation business is subject to regulation, including by the U.S. Department of Transportation ("DOT"), Department of Homeland Security, U.S. Department of Commerce and the U.S. Coast Guard ("USCG"). For information regarding these regulations, see "Regulatory Matters – Federal Regulation of Marine Operations," within this Part I, Item 1 and 2 discussion.

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

Further supporting our ethylene capabilities, we also plan to build a 24-mile, 12-inch or larger diameter ethylene pipeline extending from Mont Belvieu to Bayport, Texas. The new pipeline would have the potential to connect both producing and consuming customers located south of the Houston Ship Channel to our facility in Mont Belvieu.

Ethylene Export Marine Terminal
In January 2018, we announced the formation of a new 50/50 joint venture with Navigator Holdings Ltd. ("Navigator") to construct, own and operate an ethylene export facility along the U.S. Gulf Coast. The export facility is expected to have the capacity to export approximately 1 million tons of ethylene per year, with loading rates of approximately 1,000 tons per hour. In addition, the facility is expected to include refrigerated storage for 30,000 tons of ethylene. The project, which is underwritten by long-term contracts with customers, is expected to be completed in the first quarter of 2020. The location and final investment decisions for the terminal are subject to reaching acceptable arrangements with local taxing authorities.

Regulatory Matters

The following information describes the principal effects of regulation on our business activities, including those regulations involving safety and environmental matters and the rates we charge customers for transportation services.

Safety Matters

The safe operation of our pipelines and other assets is a top priority of our partnership. We are committed to protecting the environment and the health and safety of the public and those working on our behalf by conducting our business activities in a safe and environmentally responsible manner.

Occupational Safety and Health
Certain of our facilities are subject to the general industry requirements of the Federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes. We believe we are in material compliance with OSHA and the similar state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures of employees.

Certain of our facilities are subject to OSHA Process Safety Management ("PSM") regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process involving a chemical at or above a specified threshold (as defined in the regulations) or any process which involves certain flammable gases or liquids. In addition, we are subject to the Risk Management Plan regulations of the U.S. Environmental Protection Agency ("EPA") at certain facilities. These regulations are intended to complement the OSHA PSM regulations. These EPA regulations require us to develop and implement a risk management program that includes a five-year accident history report, an offsite consequence analysis process, a prevention program and an emergency response program. We believe we are operating in material compliance with the OSHA PSM regulations and the EPA's Risk Management Plan requirements.

The OSHA hazard communication standard, the community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act, and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to federal, state and local governmental authorities and local citizens upon request. These laws and provisions of the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") require us to report spills and releases of hazardous chemicals in certain situations.

Pipeline Safety

We are subject to extensive regulation by the DOT authorized under various provisions of Title 49 of the United States Code and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. These statutes require companies that own or operate pipelines to (i) comply with such regulations, (ii) permit access to and copying of pertinent records, (iii) file certain reports and (iv) provide information as required by the U.S. Secretary of Transportation. We believe we are in material compliance with these DOT regulations.

We are subject to DOT pipeline integrity management regulations that specify how companies should assess, evaluate, validate and maintain the integrity of pipeline segments that, in the event of a release, could impact High Consequence Areas ("HCAs"). HCAs include populated areas, unusually sensitive areas and commercially navigable waterways. The regulation requires the development and implementation of an integrity management program that utilizes internal pipeline inspection techniques, pressure testing or other equally effective means to assess the integrity of pipeline segments in HCAs. These regulations also require periodic review of HCA pipeline segments to ensure that adequate preventative and mitigative measures exist and that companies take prompt action to address integrity issues raised in the assessment and analysis process. We have identified our pipeline segments in HCAs and developed an appropriate integrity management program for such assets.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "Pipeline Safety Act") provides for regulatory oversight of the nation's pipelines, penalties for violations of pipeline safety rules, and other DOT matters. The Pipeline Safety Act increases penalties for non-compliance with its regulations for a single violation from \$100,000 to \$200,000 and imposes a maximum fine for the most serious pipeline safety violations involving deaths, injuries or major environmental harm of \$2 million per incident. In addition, the act includes additional safety requirements for newly constructed pipelines.

DOT regulations have incorporated by reference the American Petroleum Institute Standard 653 ("API 653") as the industry standard for the inspection, repair, alteration and reconstruction of storage tanks. API 653 requires regularly scheduled inspection and repair of such tanks. These periodic tank maintenance requirements may result in significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our storage tanks.

In January 2015, former President Obama announced plans to regulate methane emissions attributable to the upstream oil and gas industry, including activities related to gathering and compression, as a greenhouse gas. See "Climate Change Debate" within this Regulatory Matters section. This announcement indicated that the DOT through its Pipeline and Hazardous Materials Safety Administration ("PHMSA"), would be issuing new natural gas regulations with the intent to improve safety as well as to reduce methane emissions.

In October 2015, the PHMSA issued a notice of proposed rulemaking proposing new or revised regulations of hazardous liquid pipelines in light of the lessons learned from significant hazardous liquid pipeline accidents, including proposals to: extend reporting requirements to all hazardous liquid gravity and gathering lines; require inspections of pipelines in areas affected by extreme weather; require periodic inline integrity assessments of hazardous liquid pipelines in all locations; modify the provisions for making pipeline repairs; require all pipelines subject to the integrity management requirements be capable of accommodating inline inspection tools within 20 years, with certain exceptions; and clarification of other regulations to improve certainty and compliance.

In March 2016, the PHMSA issued a notice of proposed rulemaking recommending new safety regulations for natural gas transmission pipelines that broaden the scope of safety coverage in several ways, including but not limited to: modifying the regulation of gathering lines by eliminating the exemption from reporting requirements for gas gathering line operators and revising the definition for gathering lines; adding new assessment and revising repair criteria for pipeline segments in HCAs and establishing repair criteria for pipelines that are outside of HCAs; expanding the scope of the regulations to include pipelines located in areas of Medium Consequence Areas ("MCAs"); adding a requirement to test pipelines built before 1970, which are currently exempt from certain pipeline safety requirements; modifying the way that pipeline operators secure and inspect transmission pipeline infrastructure following extreme weather events; clarifying requirements for conducting risk assessment for integrity management; expanding mandatory data collection and integration requirements for integrity management, including data validation; requiring new safety features for launchers and receivers; and requiring a systematic approach to verify a pipeline's maximum allowable operating pressure and requiring operators to report maximum allowable operating pressure exceedances.

In June 2016, new pipeline safety legislation, the "Securing America's Future Energy: Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016" (the "SAFE PIPES Act") was signed into law. Extending the PHMSA's statutory mandate through 2019, the SAFE PIPES Act establishes or continues the development of requirements affecting pipeline safety including, but not limited to, the following: (i) providing the PHMSA with additional authority to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing; (ii) obligating the PHMSA to develop safety standards for natural gas storage facilities by June 22, 2018; and (iii) requiring the PHMSA to complete certain of the outstanding mandates under existing legislation and to report to Congress on the status of overdue rulemakings. The development and/or implementation of more stringent requirements pursuant to regulations implementing all of the requirements of the Pipeline Safety Act or the SAFE PIPES Act could cause us to incur increased capital costs and costs of operation as necessary to comply with such standards, which costs could be significant. These new regulations could increase our operating costs which could have an adverse effect on our financial position, results of operations and cash flows. Until the proposed regulations are finalized, the impact on our operations, if any, is not known.

Environmental Matters

Our operations are subject to various environmental and safety requirements and potential liabilities under extensive federal, state and local laws and regulations. These include, without limitation: the CERCLA; the Resource Conservation and Recovery Act ("RCRA"); the Federal Clean Air Act ("CAA"); the Clean Water Act ("CWA"); the Oil Pollution Act of 1990 ("OPA"); the OSHA; the Emergency Planning and Community Right to Know Act; and comparable or analogous state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals with respect to air emissions, water quality, wastewater discharges and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could have a material adverse effect on our financial position, results of operations and cash flows.

If a leak, spill or release of hazardous substances occurs at any facilities that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove previously disposed waste products or remediate contaminated property, including situations where groundwater has been impacted. Any or all of these developments could have a material adverse effect on our financial position, results of operations and cash flows.

We believe our operations are in material compliance with applicable environmental and safety laws and regulations. In addition, we expect that compliance with existing environmental and safety laws and regulations will not have a material adverse effect on our financial position, results of operations and cash flows. However, environmental and safety laws and regulations are subject to change. The trend in environmental regulation has been to place more restrictions and limitations on activities that may be perceived to impact the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. New or revised regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our financial position, results of operations and cash flows.

On occasion, we are assessed monetary sanctions by governmental authorities related to administrative or judicial proceedings involving environmental matters. See Part I, Item 3 of this annual report for additional information.

Air Quality

Our operations are associated with regulatory permitted emissions of air pollutants. As a result, we are subject to the CAA and comparable state laws and regulations including state air quality implementation plans. These laws and regulations regulate emissions of air pollutants from various industrial sources, including certain of our facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase in existing air emissions, obtain and strictly comply with the requirements of air permits containing various emission and operational limitations, or utilize specific emission control technologies to limit emissions. Increasingly, environmental groups are challenging permit modification and permit renewal requests to seek more stringent provisions. Our failure to comply with applicable requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and enforcement actions, and our inability to renew or secure a needed modification to existing permits could adversely affect our operations. We may also be required to incur certain capital expenditures for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Water Quality

The CWA and comparable state laws impose strict controls on the discharge of crude oil and its derivatives into regulated waters. The CWA provides penalties for any discharge of petroleum products in reportable quantities and imposes substantial potential liability for the costs of removing petroleum or other hazardous substances. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of a release of petroleum or its derivatives in navigable waters or into groundwater. Spill prevention control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent a petroleum tank release from impacting regulated waters. The EPA has also adopted regulations that require us to have permits in order to discharge certain storm water run-off. Storm water discharge permits may also be required by certain states in which we operate and may impose certain monitoring and other requirements. The CWA further prohibits discharges of dredged and fill material in wetlands and other waters of the U.S. unless authorized by an appropriately issued permit. We believe that our costs of compliance with these CWA requirements will not have a material adverse effect on our financial position, results of operations and cash flows.

The primary federal law for crude oil spill liability is the OPA, which addresses three principal areas of crude oil pollution: prevention, containment and clean-up and liability. The OPA applies to vessels, offshore platforms and onshore facilities, including terminals, pipelines and transfer facilities. In order to handle, store or transport crude oil above certain thresholds, onshore facilities are required to file oil spill response plans with the USCG, the DOT's Office of Pipeline Safety ("OPS") or the EPA, as appropriate. Numerous states have enacted laws similar to the OPA. Under the OPA and similar state laws, responsible parties for a regulated facility from which crude oil is discharged may be liable for remediation costs, including damage to surrounding natural resources. Any unpermitted release of petroleum or other pollutants from our pipelines or facilities could result in fines or penalties as well as significant remediation costs.

Contamination resulting from spills or releases of petroleum products is an inherent risk within the pipeline industry. To the extent that groundwater contamination requiring remediation exists along our pipeline systems or other facilities as a result of past operations, we believe any such contamination could be controlled or remedied without having a material adverse effect on our financial position, results of operations and cash flows, but such costs are site specific and there is no assurance that the impact will not be material in the aggregate.

Environmental groups have instituted lawsuits regarding certain nationwide permits issued by the U.S. Army Corps of Engineers. These permits allow for streamlined permitting of pipeline projects. If these lawsuits are successful, timelines for future pipeline construction projects could be adversely impacted.

Disposal of Hazardous and Non-Hazardous Wastes
In our normal operations, we generate hazardous and non-hazardous solid wastes that are subject to requirements of the federal RCRA and comparable state statutes, which impose detailed requirements for the handling, storage, treatment and disposal of solid waste. We also utilize waste minimization and recycling processes to reduce the volumes of our solid wastes.

CERCLA, also known as "Superfund," imposes liability, often without regard to fault or the legality of the original act, on certain classes of persons who contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of a facility where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at a facility. Under CERCLA, responsible parties may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA and RCRA also authorize the EPA and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible parties. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, our pipeline systems and other facilities generate wastes that may fall within CERCLA's definition of a "hazardous substance" or be subject to CERCLA and RCRA remediation requirements. It is possible that we could incur liability for remediation or reimbursement of remediation costs under CERCLA or RCRA for remediation at sites we currently own or operate, whether as a result of our or our predecessors' operations, at sites that we previously owned or operated, or at disposal facilities previously used by us, even if such disposal was legal at the time it was undertaken.

Endangered Species
The federal Endangered Species Act, as amended, and comparable state laws, may restrict commercial or other activities that affect endangered and threatened species or their habitats. Some of our current or future planned facilities may be located in areas that are designated as a habitat for endangered or threatened species and, if so, may limit or impose increased costs on facility construction or operation. In addition, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

FERC Regulation – Liquids Pipelines

Certain of our NGL, refined products and crude oil pipeline systems have interstate common carrier movements subject to regulation by the FERC under the Interstate Commerce Act ("ICA"). Pipelines providing such movements (referred to as "interstate liquids pipelines") include, but are not limited to, the following: ATEX, Aegis, Dixie Pipeline, TE Products Pipeline, Front Range Pipeline, Mid-America Pipeline System, Seaway Pipeline, Seminole Pipeline and Texas Express Pipeline. These pipelines are owned by legal entities whose movements are subject to FERC regulation, including periodic reporting requirements. For example, ATEX, Aegis and the TE Products Pipeline are owned by Enterprise TE Products Pipeline Company LLC ("Enterprise TE"), which provides FERC-regulated movements.

The ICA prescribes that the interstate rates we charge for transportation on these interstate liquids pipelines must be just and reasonable, and that the rules applied to our services not unduly discriminate against or confer any undue preference upon any shipper. The FERC regulations implementing the ICA further require that interstate liquids pipeline transportation rates and rules be filed with the FERC. The ICA permits interested persons to challenge proposed new or changed rates or rules, and authorizes the FERC to investigate such changes and to suspend their effectiveness for a period of up to seven months. Upon completion of such an investigation, the FERC may require refunds of amounts collected above what it finds to be a just and reasonable level, together with interest. The FERC may also investigate, upon complaint or on its own motion, rates and related rules that are already in effect, and may order a carrier to change them prospectively. Upon an appropriate showing, a shipper may obtain reparations (including interest) for damages sustained for a period of up to two years prior to the filing of its complaint.

The rates charged for our interstate liquids pipeline services are generally based on a FERC-approved indexing methodology, which allows a pipeline to charge rates up to a prescribed ceiling that changes annually based on the year-to-year change in the U.S. Producer Price Index for Finished Goods ("PPI"). A rate increase within the indexed rate ceiling is presumed to be just and reasonable unless a protesting party can demonstrate that the rate increase is substantially in excess of the pipeline's operating costs. For the five-year period commencing July 1, 2011 and ending June 30, 2016, we were permitted by the FERC to adjust the indexed rate ceilings annually by the PPI plus 2.65%. For the five-year period commencing July 1, 2016, the FERC established PPI plus 1.23% as the index. In any year in which the index is negative due to a decline in the PPI, a pipeline must file to lower its rates if its rates would be above the indexed rate ceiling. This situation occurred for the year beginning on July 1, 2016 and resulted in the FERC index applicable to our rates reflecting an approximate 2.01% decline. As an alternative to this indexing methodology, we may also choose to support changes in our rates based on a cost-of-service methodology, by obtaining advance approval to charge "market-based rates," or by charging "settlement rates" agreed to by all affected shippers.

In June 2013, certain parties filed a complaint at the FERC against Enterprise TE alleging that Enterprise TE's cancellation of certain distillate and jet fuel transportation services violated a provision of a settlement agreement and requested reinstatement of the transportation services and damages. In October 2013, the FERC issued an order holding that Enterprise TE violated the provision in the settlement agreement. While the FERC found that it did not have authority to require Enterprise TE to reinstate the cancelled services, it set the case for an evidentiary hearing to determine if any monetary damages were appropriate. Certain parties requested rehearing of the FERC's finding that it lacked authority to reinstate the cancelled services. In December 2013, Enterprise TE filed a petition for review of the FERC's October 2013 order with the U.S. Court of Appeals for the District of Columbia Circuit (the "D.C. Circuit"). Certain parties requested rehearing of the October 2013 order. In May 2016, the FERC issued an order denying those rehearing requests. Two of the parties that sought rehearing have filed a petition for review of both the October 2013 order and the May 2016 rehearing order. Enterprise TE has negotiated settlements that have resolved the complaints and has intervened in the pending third party petition for review. Since Enterprise TE has intervened on behalf of the FERC in the third party petition for review, Enterprise TE voluntarily dismissed its own petition for review at the D.C. Circuit. We are unable to predict the outcome of the pending third party petition for review, which is set for oral argument before the court in February 2018.

Seaway is charging "committed shipper" rates to shippers who voluntarily agreed under long-term contracts to commit to the transportation of, or nevertheless to pay for (to the extent not transported) the transportation of, a minimum volume of crude oil from Cushing, Oklahoma to the Gulf Coast. Seaway is also charging "uncommitted shipper" rates to shippers who have not made any long-term contractual commitment to the Seaway Pipeline and instead receive service month-to-month. In March 2013, the FERC issued a declaratory order stating that the charging by a pipeline of voluntarily agreed-to committed shipper rates is consistent with the FERC's policy of honoring contracts (the "March 2013 Order"). In light of the March 2013 Order, we believed that Seaway's committed shipper rates were not at issue in the ongoing rate proceeding, which began in 2012. However, in September 2013, an administrative law judge ("ALJ") issued an initial decision in the rate proceeding (the "2013 Initial Decision") distinguishing the March 2013 Order and recommending that the FERC find, among other things, that Seaway's committed shipper rates are not just and reasonable and should be re-determined on a cost of service basis along with the uncommitted shipper rates.

In October 2013, Seaway and certain committed rate shippers filed briefs on exceptions objecting to this committed shipper rate aspect of the ALJ's 2013 Initial Decision, and also challenging various aspects of the cost of service determinations in the 2013 Initial Decision. In February 2014, the FERC issued an order reversing the 2013 Initial Decision with respect to the committed rate issue, reiterating its policy of honoring contracts executed between pipelines and committed shippers and remanding the remaining issues to the ALJ for further review. In May 2014, the ALJ issued an initial decision on remand, which largely repeated its prior findings, including as to the committed shipper rates. In February 2016, the FERC again reversed the ALJ decision with respect to the committed rate issue and upheld Seaway's committed rates. The FERC's February 2016 order also ruled for and against Seaway on various issues related to the uncommitted rates and required Seaway to submit, by March 17, 2016, a compliance filing calculating new uncommitted rates consistent with the FERC's order. Seaway submitted its compliance filing on March 17, 2016 and it was accepted by the FERC in August 2016. In September 2016, certain parties filed protests alleging that Seaway had not reduced the uncommitted rates by reflecting the FERC's published index for 2016 and therefore the rates were not just and reasonable. In September 2016, the FERC accepted Seaway's filing, subject to the condition that Seaway refile its uncommitted rates to reflect the 2016 index adjustment and refund the difference between the rates charged and the rates reflecting the adjustment. In addition, the FERC directed Seaway to file a refund report. In September 2016, Seaway paid refunds and filed revised rates reflecting the 2016 index adjustment that became effective in October 2016. In November 2016, Seaway filed its refund report.

In December 2014, Seaway submitted an application requesting market-based rate setting authority. Certain parties filed protests to the application. In September 2015, the FERC issued an order setting the matter for hearing. In December 2016, an ALJ issued an initial decision in the market-based rate proceeding ("2016 Initial Decision") finding that the FERC should grant Seaway's application for market-based rates. Parties filed briefs in support of and in opposition to the 2016 Initial Decision, and the 2016 Initial Decision is subject to review by the FERC. We are unable to predict the ultimate outcome on the rates Seaway charges its shippers.

In October 2016, the FERC issued an advance notice of proposed rulemaking seeking comment regarding potential modifications to its policies for evaluating oil pipeline indexed rate changes and to the reporting requirements. The FERC observed that some pipelines continue to obtain additional index rate increases despite reporting on Form No. 6 that their revenues exceed their costs. The FERC is proposing a new policy that would deny proposed index increases if a pipeline's Form No. 6 reflects revenues exceeding total cost of service by 15% for both of the prior two years or the proposed index increases exceed by 5% the annual cost changes reported by the pipeline. The FERC also is considering requiring pipelines to file additional information for crude and product pipelines, non-contiguous systems and major pipeline systems. Initial comments were filed in January 2017, and reply comments were filed in March 2017. We are unable to predict the outcome of this proceeding.

In December 2016, the FERC issued a Notice of Inquiry ("NOI"), following the recent holding by the D. C. Circuit that the FERC failed to demonstrate that there is no double recovery of taxes for a partnership pipeline as a result of the inclusion of the income tax allowance in a pipeline's cost of service. Historically, claims of double recovery have arisen when the FERC has considered permitting master limited partnerships ("MLPs") to recover an income tax allowance under the FERC's current income tax allowance policy. Although the issue of income tax allowance arose in the context of an oil pipeline formed as an MLP, the NOI is not limited in its scope to MLPs. Initial and reply comments in response to the NOI were filed in March 2017 and April 2017, respectively. We are unable to predict the outcome of this proceeding.

Changes in the FERC's methodologies for approving rates could adversely affect Enterprise. In addition, challenges to our regulated rates could be filed with the FERC and future decisions by the FERC regarding our regulated rates could adversely affect our cash flows. We believe the transportation rates currently charged by our interstate liquids pipelines are in accordance with the ICA and applicable FERC regulations. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by such pipelines.

FERC Regulation – Natural Gas Pipelines and Related Matters

Certain of our intrastate natural gas pipelines, including our Texas Intrastate System and our Acadian Gas System, are subject to regulation by the FERC under the Natural Gas Policy Act of 1978 ("NGPA"), in connection with the transportation and storage services they provide pursuant to Section 311 of the NGPA. Under Section 311 of the NGPA, and the FERC's implementing regulations, an intrastate pipeline may transport gas "on behalf of" an interstate pipeline company or any local distribution company served by an interstate pipeline, without becoming subject to the FERC's broader regulatory authority under Natural Gas Act of 1938 ("NGA"). These services must be provided on an open and nondiscriminatory basis, and the rates charged for these services may not exceed a "fair and equitable" level as determined by the FERC in periodic rate proceedings.

We believe that the transportation rates currently charged and the services performed by our natural gas pipelines are all in accordance with the applicable requirements of the NGPA and FERC regulations. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by our pipelines.

The resale of natural gas in interstate commerce is subject to FERC oversight. In order to increase transparency in natural gas markets, the FERC has established rules requiring the annual reporting of data regarding natural gas sales. The FERC has also established regulations that prohibit energy market manipulation. The Federal Trade Commission and the Commodity Futures Trading Commission ("CFTC") have also issued rules and regulations prohibiting energy market manipulation. We believe that our gas sales activities are in compliance with all applicable regulatory requirements.

A violation of the FERC's regulations may subject us to civil penalties, suspension or loss of authorization to perform services or make sales of natural gas, disgorgement of unjust profits or other appropriate non-monetary remedies imposed by the FERC. Pursuant to the Energy Policy Act of 2005, the potential civil and criminal penalties for any violation of the NGPA, or any rules, regulations or orders of the FERC, were increased to up to $1 million per day per violation.

State Regulation of Pipeline Transportation Services

Transportation services rendered by our intrastate liquids and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Illinois, Kansas, Louisiana, Minnesota, Mississippi, New Mexico, Oklahoma, Texas and Wyoming. Although the applicable state statutes and regulations vary widely, they generally require that intrastate pipelines publish tariffs setting forth all rates, rules and regulations applying to intrastate service, and generally require that pipeline rates and practices be reasonable and nondiscriminatory.

Federal Regulation of Marine Operations

The operation of tow boats, barges and marine equipment create maritime obligations involving property, personnel and cargo under General Maritime Law. These obligations create a variety of risks including, among other things, the risk of collision and allision, which may precipitate claims for personal injury, cargo, contract, pollution, third party claims and property damages to vessels and facilities.

We are subject to the Jones Act and other federal laws that restrict maritime transportation between U.S. departure and destination points to vessels built and registered in the U.S. and owned and manned by U.S. citizens. As a result of this ownership requirement, we are responsible for monitoring the foreign ownership of our common units and other partnership interests. If we do not comply with such requirements, we would be prohibited from operating our vessels in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of the vessels. In addition, the USCG and American Bureau of Shipping maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for U.S.-flagged operators than for owners of vessels registered under foreign flags of convenience. Our marine operations are also subject to the Merchant Marine Act of 1936, which under certain conditions would allow the U.S. government to requisition our marine assets in the event of a national emergency.

Climate Change Debate

There is considerable debate over global warming and the environmental effects of greenhouse gas emissions and associated consequences affecting global climate, oceans and ecosystems. As a commercial enterprise, we are not in a position to validate or repudiate the existence of global warming or various aspects of the scientific debate. However, if global warming is occurring, it could have an impact on our operations. For example, our facilities that are located in low lying areas such as the coastal regions of Louisiana and Texas may be at increased risk due to flooding, rising sea levels, or disruption of operations from more frequent and severe weather events. Facilities in areas with limited water availability may be impacted if droughts become more frequent or severe. Changes in climate or weather may hinder exploration and production activities or increase the cost of production of oil and gas resources and consequently affect the volume of hydrocarbon products entering our system. Changes in climate or weather may also affect consumer demand for energy or alter the overall energy mix. However, we are not in a position to predict the precise effects of global climate change. We are providing this disclosure based on publicly available information on the matter.

In response to scientific studies suggesting that emissions of certain gases, commonly referred to as greenhouse gases, including gases associated with oil and gas production such as carbon dioxide, methane and nitrous oxide among others, may be contributing to a warming of the earth's atmosphere and other adverse environmental effects, various governmental authorities have considered or taken actions to reduce emissions of greenhouse gases. For example, the EPA has taken action under the CAA to regulate greenhouse gas emissions. In addition, certain states (individually or in regional cooperation), including states in which some of our facilities or operations are located, have taken or proposed measures to reduce emissions of greenhouse gases. Also, the U.S. Congress has proposed legislative measures for imposing restrictions or requiring emissions fees for greenhouse gases.

Actions have also taken place at the international level, and the U.S. has been actively involved. Various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy, or use of fuels with lower carbon content are under discussion and have and may continue to result in additional actions involving greenhouse gases.

These federal, regional and state measures generally apply to industrial sources (including facilities in the oil and gas sector) and suppliers and distributors of fuel, and could increase the operating and compliance costs of our pipelines, natural gas processing plants, fractionation plants and other facilities, and the costs of certain sale and distribution activities. These regulations could also adversely affect market demand or pricing for our products or products served by our midstream infrastructure, by affecting the price of, or reducing the demand for, fossil fuels or providing competitive advantages to competing fuels and energy sources. The potential increase in the costs of our operations could include costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions, or administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities, such recovery of costs is uncertain and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC and the provisions of any final regulations. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products that are deemed to contribute to greenhouse gases, or restrictions on their use, may reduce volumes available to us for processing, transportation, marketing and storage.

Competition

NGL Pipelines & Services

Within their respective market areas, our natural gas processing business activities and related NGL marketing activities encounter competition primarily from fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-rate regulated affiliates, financial institutions with commodity trading platforms and independent processors. Each of our marketing competitors has varying levels of financial and personnel resources, and competition generally revolves around price, quality of customer service and proximity to customers and other market hubs. In the markets served by our NGL pipelines, we compete with a number of intrastate and interstate pipeline companies (including those affiliated with major oil, petrochemical and natural gas companies) and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees, reliability and quality of customer service.

Our primary competitors in the NGL and related product storage businesses are integrated major oil companies, chemical companies and other storage and pipeline companies. We compete with other storage service providers primarily in terms of the fees charged, number of pipeline connections provided and operational dependability. Our import and export operations compete with those operated by major oil and chemical companies and other midstream service providers primarily in terms of loading and offloading throughput capacity.

We compete with a number of NGL fractionators in Kansas, Louisiana, New Mexico and Texas. Competition for such services is primarily based on the fractionation fee charged. However, the ability of an NGL fractionator to receive a customer's mixed NGLs and store and distribute the resulting purity NGL products is also an important competitive factor and is a function of having the necessary pipeline and storage infrastructure.

Crude Oil Pipelines & Services

Within their respective market areas, our crude oil pipelines, storage terminals and related marketing activities compete with other crude oil pipeline companies, rail carriers, major integrated oil companies and their marketing affiliates, financial institutions with commodity trading platforms and independent crude oil gathering and marketing companies. The crude oil business can be characterized by strong competition for crude oil volumes. Competition is based primarily on quality of customer service, competitive pricing and proximity to customers and market hubs.

Natural Gas Pipelines & Services

Within their market areas, our natural gas pipelines compete with other natural gas pipelines on the basis of price (in terms of transportation fees), quality of customer service and operational flexibility. Our natural gas marketing activities compete primarily with other natural gas pipeline companies and their marketing affiliates as well as standalone natural gas marketing and trading firms. Competition in the natural gas marketing business is based primarily on competitive pricing, proximity to customers and market hubs, and quality of customer service.

Petrochemical & Refined Products Services

We compete with numerous producers of PGP, which include many of the major refiners and petrochemical companies located along the Gulf Coast. Generally, our propylene fractionation business competes in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our petrochemical marketing activities encounter competition from fully integrated oil companies and various petrochemical companies. Our petrochemical marketing competitors have varying levels of financial and personnel resources and competition generally revolves around price, quality of customer service, logistics and location.

With respect to our isomerization operations, we compete primarily with facilities located in Kansas, Louisiana and New Mexico. Competitive factors affecting this business include the level of toll processing fees charged, the quality of isobutane that can be produced and access to supporting pipeline and storage infrastructure. We compete with other octane additive manufacturing companies primarily on the basis of price.

With respect to our TE Products Pipeline, the pipeline's most significant competitors are third party pipelines in the areas where it delivers products. Competition among common carrier pipelines is based primarily on transportation fees, quality of customer service and proximity to end users. Trucks, barges and railroads competitively deliver products into some of the markets served by our TE Products Pipeline and river terminals. The TE Products Pipeline also faces competition from rail and pipeline movements of NGLs from Canada and waterborne imports into terminals located along the upper East Coast.

Our marine transportation business competes with other inland marine transportation companies as well as providers of other modes of transportation, such as rail tank cars, tractor-trailer tank trucks and, to a limited extent, pipelines. Competition within the marine transportation business is largely based on performance and price.

Seasonality

Although the majority of our businesses are not materially affected by seasonality, certain aspects of our operations are impacted by seasonal changes such as tropical weather events, energy demand in connection with heating and cooling requirements and for the summer driving season. Examples include:

- Our operations along the Gulf Coast, including our Mont Belvieu facility, may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

- Residential demand for natural gas typically peaks during the winter months in connection with heating needs and during the summer months for power generation for air conditioning. These seasonal trends affect throughput volumes on our natural gas pipelines and associated natural gas storage levels and marketing results.

- Due to increased demand for fuel additives used in the production of motor gasoline, our isomerization and octane enhancement businesses experience higher levels of demand during the summer driving season, which typically occurs in the spring and summer months. Likewise, shipments of refined products and normal butane experience similar changes in demand due to their use in motor fuels.

- Extreme temperatures and ice during the winter months can negatively affect our trucking and inland marine operations on the upper Mississippi and Illinois rivers.

Title to Properties

Our real property holdings fall into two basic categories: (i) parcels that we and our unconsolidated affiliates own in fee (e.g., we own the land upon which our Mont Belvieu NGL fractionators are constructed) and (ii) parcels in which our interests and those of our affiliates are derived from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. The fee sites upon which our significant facilities are located have been owned by us or our predecessors in title for many years without any material challenge known to us relating to title to the land upon which the assets are located, and we believe that we have satisfactory title to such fee sites. We and our affiliates have no knowledge of any material challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our rights pursuant to any material lease, easement, right-of-way, permit or license, and we believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses.

Available Information

As a publicly traded partnership, we electronically file certain documents with the U.S. Securities and Exchange Commission ("SEC"). We file annual reports on Form 10-K; quarterly reports on Form 10-Q; and current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. Occasionally, we may also file registration statements and related documents in connection with equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at (800) SEC-0330. In addition, the SEC maintains a website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC.

We provide free electronic access to our periodic and current reports on our website, www.enterpriseproducts.com. These reports are available as soon as reasonably practicable after we electronically file such materials with, or furnish such materials to, the SEC. You may also contact our Investor Relations department at (866) 230-0745 for paper copies of these reports free of charge. The information found on our website is not incorporated into this annual report.

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

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

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

Marquard & Bahls AG ("M&B"), a German corporation and the former parent company of Oiltanking, is entitled to designate a nominee for election to the Board (the "M&B Designee") as long as M&B and its affiliates beneficially own at least 27,403,676 of the common units we issued to M&B and its affiliates in connection with step one of the Oiltanking acquisition. In the event that the M&B Designee becomes unable or unwilling to, or for another reason ceases to, serve as a member of the Board while M&B is entitled to maintain the M&B Designee, M&B may designate another person reasonably acceptable to the Board as a replacement. The initial M&B Designee, Dr. F. Christian Flach, resigned from the Board in November 2017. No replacement for Dr. Flach has been nominated by M&B as of the filing date of this annual report.

M&B owns and controls Oiltanking GmbH, which in turn owns a joint venture interest in the Exir Chemical Terminal ("ECT") in Iran via its wholly owned affiliates Oiltanking ME Holding GmbH (formerly named Oiltanking Iran GmbH) and OMEA GmbH. This interest results from an investment dating back to 2002. Oiltanking GmbH currently has the contractual right to vote for the appointment of two members of ECT's three-member board. Oiltanking GmbH provides no goods, services, technology, information or support to ECT and plays no role in the management or day-to-day operations of ECT.

ECT stores chemicals and hydrocarbons, including naphtha, linear alkyl benzene and n-hexane, for distribution in Iran and for export to Asia and Europe. To our knowledge, ECT's activities are in compliance with applicable U.S., European Union or United Nations sanctions laws. ECT pays routine and standard charges (i) to the Petrochemical Special Economic Zone Organization ("Petzone") for the use of pipelines and (ii) to the National Petrochemical Company ("NPC"), which operates the berth. Petzone is a subsidiary of NPC, which is owned and controlled by the Government of Iran. As Oiltanking GmbH has no direct involvement in the day-to-day operations of ECT, we have no information regarding ECT's intent to continue or not continue making the payments described above.

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

Item 1A. *Risk Factors.*

An investment in our common units or debt securities involves certain risks. If any of the following key risks were to occur, it could have a material adverse effect on our financial position, results of operations and cash flows, as well as our ability to maintain or increase distribution levels. In any such circumstance and others described below, the trading price of our securities could decline and you could lose part or all of your investment.

Risks Relating to Our Business

Changes in demand for and prices and production of hydrocarbon products could have a material adverse effect on our financial position, results of operations and cash flows.

We operate predominantly 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.

Crude oil and natural gas prices have been extremely volatile in recent years, and we expect that volatility to continue. For example, crude oil prices (based on WTI as measured by the NYMEX) ranged from a high of $61.43 per barrel to a low of $26.21 per barrel in the three year period ending December 31, 2017. Likewise, natural gas prices (based on Henry Hub as measured by the NYMEX) ranged from a high of $3.93 per MMBtu to a low of $1.64 per MMBtu over the same three year period.

Generally, prices of hydrocarbon products are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of other uncontrollable factors, such as: (i) the level of domestic production and consumer product demand; (ii) the availability of imported oil and natural gas and actions taken by foreign crude oil and natural gas producing nations; (iii) the availability of transportation systems with adequate capacity; (iv) the availability of competitive fuels; (v) fluctuating and seasonal demand for crude oil, natural gas, NGLs and other hydrocarbon products, including demand for NGL products by the petrochemical, refining and heating industries; (vi) the impact of conservation efforts; (vii) governmental regulation and taxation of production; and (viii) prevailing economic conditions.

We are exposed to natural gas and NGL commodity price risks under certain of our natural gas processing and gathering and NGL fractionation contracts that provide for fees to be calculated based on a regional natural gas or NGL price index or to be paid in-kind by taking title to natural gas or NGLs. A decrease in natural gas and NGL prices can result in lower margins from these contracts, which could have a material adverse effect on our financial position, results of operations and cash flows. Volatility in the prices of natural gas and NGLs can lead to ethane rejection, which results in lower pipeline and fractionation volumes for our assets. Volatility in these commodity prices may also have an impact on many of our customers, which in turn could have a negative impact on their ability to fulfill their obligations to us.

The crude oil, natural gas and NGLs currently transported, gathered or processed at our facilities originate primarily from existing domestic resource basins, which naturally deplete over time. To offset this natural decline, our facilities need access to production from newly discovered properties. Many economic and business factors beyond our control can adversely affect the decision by producers to explore for and develop new reserves. These factors could include relatively low oil and natural gas prices, cost and availability of equipment and labor, regulatory changes, capital budget limitations, the lack of available capital or the probability of success in finding hydrocarbons. A decrease in exploration and development activities in the regions where our facilities and other energy logistics assets are located could result in a decrease in volumes handled by our assets, which could have a material adverse effect on our financial position, results of operations and cash flows.

For a discussion regarding our current commercial outlook for 2018, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Outlook for 2018" included under Part II, Item 7 of this annual report.

We face competition from third parties in our midstream energy businesses.

Even if crude oil and natural gas reserves exist in the areas served by our assets, we may not be chosen by producers in these areas to gather, transport, process, fractionate, store or otherwise handle the hydrocarbons extracted. We compete with other companies, including producers of crude oil and natural gas, for any such production on the basis of many factors, including but not limited to geographic proximity to the production, costs of connection, available capacity, rates and access to markets.

Our NGL, refined products and marine transportation businesses may compete with other pipelines and marine transportation companies in the areas they serve. We also compete with railroads and third party trucking operations in certain of the areas we serve. Competitive pressures may adversely affect our tariff rates or volumes shipped. Also, substantial new construction of inland marine vessels could create an oversupply and intensify competition for our marine transportation business.

The crude oil gathering and marketing business can be characterized by thin operating margins and intense competition for supplies of crude oil at the wellhead. A decline in domestic crude oil production could intensify this competition among gatherers and marketers. Our crude oil transportation business competes with common carriers and proprietary pipelines owned and operated by major oil companies, large independent pipeline companies, financial institutions with commodity trading platforms and other companies in the areas where such pipeline systems deliver crude oil.

In our natural gas gathering business, we encounter competition in obtaining contracts to gather natural gas supplies, particularly new supplies. Competition in natural gas gathering is based in large part on reputation, efficiency, system reliability, gathering system capacity and pricing arrangements. Our key competitors in the natural gas gathering business include independent gas gatherers and major integrated energy companies. Alternate gathering facilities are available to producers we serve, and those producers may also elect to construct proprietary gas gathering systems.

Both we and our competitors make significant investments in new energy infrastructure to meet anticipated market demand. The success of our projects depends on utilization of our assets. Demand for our new projects may change during construction, and our competitors may make additional investments or redeployments of assets that compete with our projects and existing assets. If either our investments or construction by competitors in the markets we serve result in excess capacity, our facilities and assets could be underutilized, which could cause us to reduce rates for our services, and to reduce the returns on our investments and value of our assets.

A significant increase in competition in the midstream energy industry, including construction of new assets or redeployment of existing assets by our competitors, could have a material adverse effect on our financial position, results of operations and cash flows.

Our debt level may limit our future financial and operating flexibility.

As of December 31, 2017, we had $19.85 billion in principal amount of consolidated senior long-term debt outstanding, $3.17 billion in principal amount of junior subordinated debt outstanding and $1.76 billion in short-term commercial paper notes outstanding. The amount of our future debt could have significant effects on our operations, including, among other things:

- a substantial portion of our cash flow could be dedicated to the payment of principal and interest on our future debt and may not be available for other purposes, including the payment of distributions on our common units and capital expenditures;

- credit rating agencies may take a negative view of our consolidated debt level;

- covenants contained in our existing and future credit and debt agreements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- we may be at a competitive disadvantage relative to similar companies that have less debt; and

- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

Our public debt indentures currently do not limit the amount of future indebtedness that we can incur, assume or guarantee. Although our credit agreements restrict our ability to incur additional debt above certain levels, any debt we may incur in compliance with these restrictions may still be substantial. For information regarding our long-term debt, see Note 8 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Our credit agreements and each of the indentures related to our public debt instruments include traditional financial covenants and other restrictions. For example, we are prohibited from making distributions to our partners if such distributions would cause an event of default or otherwise violate a covenant under our credit agreements. A breach of any of these restrictions by us could permit our lenders or noteholders, as applicable, to declare all amounts outstanding under these debt agreements to be immediately due and payable and, in the case of our credit agreements, to terminate all commitments to extend further credit.

Our ability to access capital markets to raise capital on favorable terms could be affected by our debt level, when such debt matures, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, we could experience an increase in our borrowing costs, difficulty assessing capital markets and/or a reduction in the market price of our securities. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures or acquisitions, or to refinance existing indebtedness. If we are unable to access the capital markets on favorable terms in the future, we might be forced to seek extensions for some of our short-term debt obligations or to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected levels.

We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for investment opportunities.

Our growth strategy contemplates the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses that enhance our ability to compete effectively and to diversify our asset portfolio, thereby providing us with more stable cash flows. We consider and pursue potential joint ventures, standalone projects and other transactions that we believe may present opportunities to expand our business, increase our market position and realize operational synergies.

We will require substantial new capital to finance the future development and acquisition of assets and businesses. For example, our capital spending for 2017 reflected approximately $3.4 billion of cash payments for capital projects and other investments. Based on information currently available, we expect our total capital spending for 2018 to approximate $3.3 billion, which includes approximately $315 million for sustaining capital expenditures. Any limitations on our access to capital may impair our ability to execute this growth strategy. If our cost of debt or equity capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We also may not be able to raise the necessary funds on satisfactory terms, if at all.

Any sustained tightening of the credit markets may have a material adverse effect on us by, among other things, decreasing our ability to finance growth capital projects or business acquisitions on favorable terms and by the imposition of increasingly restrictive borrowing covenants. In addition, the distribution yields of any new equity we may issue may be higher than historical levels, making additional equity issuances more expensive. Accordingly, increased costs of equity and debt will make returns on capital expenditures with proceeds from such capital less accretive on a per unit basis.

We also may compete with third parties in the acquisition of energy infrastructure assets that complement our existing asset base. Increased competition for a limited pool of assets could result in our losing to other bidders more often than in the past or acquiring assets at less attractive prices. Either occurrence could limit our ability to fully execute our growth strategy. Our inability to execute our growth strategy may materially adversely affect our ability to maintain or pay higher cash distributions in the future.

Our actual construction, development and acquisition costs could materially exceed forecasted amounts.

We have announced and are engaged in multiple significant construction projects involving existing and new assets for which we have expended or will expend significant capital. These projects entail significant logistical, technological and staffing challenges. We may not be able to complete our projects at the costs we estimated at the time of each project's initiation or that we currently estimate. Similarly, force majeure events such as hurricanes along the U.S. Gulf Coast may cause delays, shortages of skilled labor and additional expenses for these construction and development projects.

If capital expenditures materially exceed expected amounts, then our future cash flows could be reduced, which, in turn, could reduce the amount of cash we expect to have available for distribution. In addition, a material increase in project costs could result in decreased overall profitability of the newly constructed asset once it is placed into commercial service.

Our construction of new assets is subject to operational, regulatory, environmental, political, legal and economic risks, which may result in delays, increased costs or decreased cash flows.

One of the ways we intend to grow our business is through the construction of new midstream energy infrastructure assets. The construction of new assets involves numerous operational, regulatory, environmental, political, legal and economic risks beyond our control and may require the expenditure of significant amounts of capital. These potential risks include, among other things, the following:

- we may be unable to complete construction projects on schedule or at the budgeted cost due to the unavailability of required construction personnel or materials, accidents, weather conditions or an inability to obtain necessary permits;
- we will not receive any material increase in operating cash flows until the project is completed, even though we may have expended considerable funds during the construction phase, which may be prolonged;
- we may construct facilities to capture anticipated future production growth in a region in which such growth does not materialize;
- since we are not engaged in the exploration for and development of crude oil or natural gas reserves, we may not have access to third party estimates of reserves in an area prior to our constructing facilities in the area. As a result, we may construct facilities in an area where the reserves are materially lower than we anticipate;
- in those situations where we do rely on third party reserve estimates in making a decision to construct assets, these estimates may prove inaccurate;
- the completion or success of our construction project may depend on the completion of a third party construction project (e.g., a downstream crude oil refinery expansion or construction of a new petrochemical facility) that we do not control and that may be subject to numerous of its own potential risks, delays and complexities; and
- we may be unable to obtain rights-of-way to construct additional pipelines or the cost to do so may be uneconomical.

A materialization of any of these risks could adversely affect our ability to achieve growth in the level of our cash flows or realize benefits from expansion opportunities or construction projects, which could impact the level of cash distributions we pay to partners.

Several of our assets have been in service for many years and require significant expenditures to maintain them. As a result, our maintenance or repair costs may increase in the future.

Our pipelines, terminals and storage assets are generally long-lived assets, and many of them have been in service for many years. The age and condition of our assets could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our results of operations, financial position or cash flows, as well as our ability to make cash distributions to our unitholders.

The inability to continue to access lands owned by third parties, including Native American tribes, could adversely affect our operations and have a material adverse effect on our financial position, results of operations and cash flows.

Our ability to operate our pipeline systems on certain lands owned by third parties will depend on our maintaining existing rights-of-way and obtaining new rights-of-way on those lands. We are parties to rights-of-way agreements, permits and licenses authorizing land use with numerous parties, including private land owners, governmental entities, Native American tribes, rail carriers, public utilities and others. Our ability to secure extensions of existing agreements, permits and licenses is essential to our continuing business operations, and securing additional rights-of-way will be critical to our ability to pursue expansion projects. We cannot provide any assurance that we will be able to maintain access to all existing rights-of-way upon the expiration of the current grants, that all of the rights-of-way will be obtained in a timely fashion or that we will acquire new rights-of-way as needed.

In particular, various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, Bureau of Land Management, and the Office of Natural Resources Revenue, along with each Native American tribe, promulgate and enforce regulations pertaining to natural gas and oil operations on Native American tribal lands. These regulations and approval requirements relate to such matters as drilling and production requirements and environmental standards. In addition, each Native American tribe is a sovereign nation having the right to enforce laws and regulations and to grant approvals independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees, requirements to employ Native American tribal members and other conditions that apply to operators and contractors conducting operations on Native American tribal lands. One or more of these factors may increase our cost of doing business on Native American tribal lands and impact the viability of, or prevent or delay our ability to conduct our operations on such lands.

Furthermore, whether we have the power of eminent domain for our pipelines varies from state to state, depending upon the type of pipeline and the laws of the particular state and the ownership of the land to which we seek access. When we exercise eminent domain rights or negotiate private agreements, we must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. The inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our pipelines are located.

We may face opposition to the operation of our pipelines and facilities from various groups.

We may face opposition to the operation of our pipelines and facilities from environmental groups, landowners, tribal groups, local groups and other advocates. Such opposition could take many forms, including organized protests, attempts to block or sabotage our operations, intervention in regulatory or administrative proceedings involving our assets, or lawsuits or other actions designed to prevent, disrupt or delay the operation of our assets and business. For example, repairing our pipelines often involves securing consent from individual landowners to access their property; one or more landowners may resist our efforts to make needed repairs, which could lead to an interruption in the operation of the affected pipeline or facility for a period of time that is significantly longer than would have otherwise been the case. In addition, acts of sabotage or eco-terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of our operations. Any such event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions to our partners and, accordingly, adversely affect our financial condition and the market price of our securities.

Our growth strategy may adversely affect our results of operations if we do not successfully integrate and manage the businesses that we acquire or if we substantially increase our indebtedness and contingent liabilities to make acquisitions.

Our growth strategy includes making accretive acquisitions. From time to time, we evaluate and acquire additional assets and businesses that we believe complement our existing operations. We may be unable to successfully integrate and manage the businesses we acquire in the future. We may incur substantial expenses or encounter delays or other problems in connection with our growth strategy that could have a material adverse effect on our financial position, results of operations and cash flows. Moreover, acquisitions and business expansions involve numerous risks, such as:

- difficulties in the assimilation of the operations, technologies, services and products of the acquired assets or businesses;
- establishing the internal controls and procedures we are required to maintain under the Sarbanes-Oxley Act of 2002;
- managing relationships with new joint venture partners with whom we have not previously partnered;
- experiencing unforeseen operational interruptions or the loss of key employees, customers or suppliers;
- inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including with their markets; and
- diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, amortization and accretion expenses. As a result, our capitalization and results of operations may change significantly following a material acquisition. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our financial position, results of operations and cash flows. In addition, any anticipated benefits of a material acquisition, such as expected cost savings or other synergies, may not be fully realized, if at all.

Acquisitions that appear to increase our operating cash flows may nevertheless reduce our operating cash flows on a per unit basis.

Even if we make acquisitions that we believe will increase our operating cash flows, these acquisitions may ultimately result in a reduction of operating cash flow on a per unit basis, such as if our assumptions regarding a newly acquired asset or business did not materialize or unforeseen risks occurred. As a result, an acquisition initially deemed accretive based on information available at the time could turn out not to be. Examples of risks that could cause an acquisition to ultimately not be accretive include our inability to achieve anticipated operating and financial projections or to integrate an acquired business successfully, the assumption of unknown liabilities for which we become liable, and the loss of key employees or key customers. If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will in making such decisions. As a result of the risks noted above, we may not realize the full benefits we expect from a material acquisition, which could have a material adverse effect on our financial position, results of operations and cash flows.

A natural disaster, catastrophe, terrorist or cyber-attack or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and have a material adverse effect on our financial position, results of operations and cash flows.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. In addition, our marine transportation business is subject to additional risks, including the possibility of marine accidents and spill events. From time to time, our octane enhancement facility may produce MTBE for export, which could expose us to additional risks from spill events. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. The location of our assets and our customers' assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane or tropical storm risk. In addition, terrorists may target our physical facilities and computer hackers may attack our electronic systems.

If one or more facilities or electronic systems that we own or that deliver products to us or that supply our facilities are damaged by severe weather or any other disaster, accident, catastrophe, terrorist or cyber-attack or event, our operations could be significantly interrupted. These interruptions could involve significant damage to people, property or the environment, and repairs could take from a week or less for a minor incident to six months or more for a major interruption. Additionally, some of the storage contracts that we are a party to obligate us to indemnify our customers for any damage or injury occurring during the period in which the customers' product is in our possession. Any event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions and, accordingly, adversely affect the market price of our common units.

Cybersecurity attacks are becoming more sophisticated, and include, without limitation, malicious software, ransomware, attempts to gain unauthorized access to data, and other electronic security breaches. These risks include cybersecurity attacks on both us and third parties who provide material services to us. In addition to disrupting operations, cyber security breaches could also affect our ability to operate or control our facilities, render data or systems unusable, or result in the theft of sensitive, confidential or customer information. These events could also damage our reputation, and result in losses from remedial actions, loss of business or potential liability to third parties.

We believe that EPCO maintains adequate insurance coverage on our behalf, although insurance will not cover many types of interruptions that might occur, will not cover amounts up to applicable deductibles and will not cover all risks associated with certain of our products. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage.

In the future, circumstances may arise whereby EPCO may not be able to renew existing insurance policies on our behalf or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

The use of derivative financial instruments could result in material financial losses by us.

Historically, we have sought to limit a portion of the adverse effects resulting from changes in energy commodity prices and interest rates by using derivative instruments. Derivative instruments typically include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

To the extent that we hedge our commodity price and interest rate exposures, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, hedging activities can result in losses that might be material to our financial condition, results of operations and cash flows. Such losses could occur under various circumstances, including those situations where a counterparty does not perform its obligations under a hedge arrangement, the hedge is not effective in mitigating the underlying risk, or our risk management policies and procedures are not followed. Adverse economic conditions (e.g., a significant decline in energy commodity prices that negatively impact the cash flows of oil and gas producers) increase the risk of nonpayment or performance by our hedging counterparties.

See Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for a discussion of our derivative instruments and related hedging activities.

Our business requires extensive credit risk management that may not be adequate to protect against customer nonpayment.

We may incur credit risk to the extent customers do not fulfill their obligations to us in connection with our marketing of natural gas, NGLs, crude oil, petrochemicals and refined products and long-term contracts with minimum volume commitments or fixed demand charges. Risks of nonpayment and nonperformance by customers are a major consideration in our businesses, and our credit procedures and policies may not be adequate to sufficiently eliminate customer credit risk. Further, adverse economic conditions in our industry may increase the risk of nonpayment and nonperformance by customers, particularly customers that have sub-investment grade credit ratings. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments, net out agreements and guarantees. However, these procedures and policies do not fully eliminate customer credit risk.

Our primary market areas are located in the Gulf Coast, Southwest, Rocky Mountain, Northeast and Midwest regions of the U.S. We have a concentration of trade receivable balances due from domestic and international major integrated oil companies, independent oil companies and other pipelines and wholesalers. These concentrations of market areas may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors.

See Note 2 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding our allowance for doubtful accounts.

Our risk management policies cannot eliminate all commodity price risks. In addition, any noncompliance with our risk management policies could result in significant financial losses.

When engaged in marketing activities, it is our policy to maintain physical commodity positions that are substantially balanced with respect to price risks between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Through these transactions, we seek to earn a margin for the commodity purchased by selling the commodity for physical delivery to third party users, such as producers, wholesalers, local distributors, independent refiners, marketing companies or major oil companies. These policies and practices cannot, however, eliminate all price risks. For example, any event that disrupts our anticipated physical supply could expose us to risk of loss resulting from price changes if we are required to obtain alternative supplies to cover our sales transactions. We are also exposed to basis risks when a commodity is purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including price risks on product we own, such as pipeline linefill, which must be maintained in order to facilitate transportation of the commodity in our pipelines. In addition, our marketing operations involve the risk of non-compliance with our risk management policies. We cannot assure you that our processes and procedures will detect and prevent all violations of our risk management policies, particularly if deception or other intentional misconduct is involved. If we were to incur a material loss related to commodity price risks, including non-compliance with our risk management policies, it could have a material adverse effect on our financial position, results of operations and cash flows.

Our variable-rate debt, including those fixed-rate debt obligations that may be converted to variable-rate through the use of interest rate swaps, make us vulnerable to increases in interest rates, which could have a material adverse effect on our financial position, results of operation and cash flows.

At December 31, 2017, we had $21.48 billion in principal amount of consolidated fixed-rate debt outstanding, including current maturities thereof. We also had $1.76 billion of commercial paper notes outstanding at December 31, 2017. Due to the short term nature of commercial paper notes, we view the interest rates charged in connection with these instruments as variable.

The Board of Governors of the Federal Reserve System raised benchmark interest rates three times during 2017 and has stated that it expects to raise rates again in 2018. Should interest rates increase significantly, the amount of cash required to service our debt (including any future refinancing of our fixed-rate debt instruments) would increase. Additionally, from time to time, we may enter into interest rate swap arrangements, which could increase our exposure to variable interest rates. As a result, significant increases in interest rates could have a material adverse effect on our financial position, results of operations and cash flows.

An increase in interest rates may also cause a corresponding decline in demand for equity securities in general, and in particular, for yield-based equity securities such as our common units. A reduction in demand for our common units may cause their trading price to decline.

Our pipeline integrity program as well as compliance with pipeline safety laws and regulations may impose significant costs and liabilities on us.

If we were to incur material costs in connection with our pipeline integrity program or pipeline safety laws and regulations, those costs could have a material adverse effect on our financial condition, results of operations and cash flows.

The DOT requires pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in HCAs. The majority of the costs to comply with this integrity management rule are associated with pipeline integrity testing and any repairs found to be necessary as a result of such testing. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipe determined to be located in HCAs can have a significant impact on the costs to perform integrity testing and repairs. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

In total, our pipeline integrity costs for the years ended December 31, 2017, 2016 and 2015 were $91.1 million, $103.7 million and $92.7 million, respectively. Of these annual totals, we charged $52.3 million, $55.8 million and $54.7 million to operating costs and expenses during the years ended December 31, 2017, 2016 and 2015, respectively. The remaining annual pipeline integrity costs were capitalized and treated as sustaining capital projects. We expect the cost of our pipeline integrity program, regardless of whether such costs are capitalized or expensed, to approximate $138 million for 2018.

For additional information regarding the pipeline safety regulations, the Pipeline Safety Act and the SAFE PIPES Act, see "Regulatory Matters – Safety Matters – Pipeline Safety" included under Part I, Item 1 and 2 of this annual report.

Environmental, health and safety costs and liabilities, and changing environmental, health and safety regulation, could have a material adverse effect on our financial position, results of operations and cash flows.

Our operations are subject to various environmental, health and safety requirements and potential liabilities under extensive federal, state and local laws and regulations. Further, we cannot ensure that existing environmental, health and safety regulations will not be revised or that new regulations will not be adopted or become applicable to us. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Certain environmental laws, including the CERCLA and analogous state laws and regulations, may impose strict, joint and several liability for costs required to clean-up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could have a material adverse effect on our financial position, results of operations and cash flows.

In addition, future environmental, health and safety law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of our operations. Areas of potential future environmental, health and safety law development include the following items.

Greenhouse Gases/Climate Change
Responding to scientific reports regarding threats posed by global climate change, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. In addition, some states, including states in which our facilities or operations are located, have individually or in regional cooperation, imposed restrictions on greenhouse gas emissions under various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy sources, or use of replacement fuels with lower carbon content.

The adoption and implementation of any federal, state or local regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur significant costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the crude oil, natural gas or other hydrocarbon products that we transport, store or otherwise handle in connection with our midstream services. The potential increase in our operating costs could include costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize greenhouse gas emissions (whether emitted by our operations or associated with fuel that we supply into the markets), pay taxes related to greenhouse gas emissions, and administer and manage a greenhouse gas emissions program. We may not be able to recover such increased costs through customer prices or rates, which may limit our access to, or otherwise cause us to reduce our participation in, certain market activities. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products that are deemed to contribute to greenhouse gases, or restrictions on their use, may reduce volumes available to us for processing, transportation, marketing and storage. These developments could have a material adverse effect on our financial position, results of operations and cash flows.

In addition, due to concerns over climate change, numerous countries around the world have adopted or are considering adopting laws or regulations to reduce greenhouse gas emissions. It is not possible to know how quickly renewable energy technologies may advance, but if significant additional legislation and regulation were enacted, the increased use of renewable energy could ultimately reduce future demand for hydrocarbons. These developments could have a material adverse effect on our financial position, results of operations and cash flows.

Hydraulic Fracturing
Certain of our customers employ hydraulic fracturing techniques to stimulate natural gas and crude oil production from unconventional geological formations (including shale formations), which entails the injection of pressurized fracturing fluids (consisting of water, sand and certain chemicals) into a well bore. The U.S. federal government, and some states and localities, have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, or that would impose higher taxes, fees or royalties on natural gas production. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to crude oil and natural gas drilling activities using hydraulic fracturing techniques, including increased litigation. Additional legislation or regulation could also lead to operational delays and/or increased operating costs in the production of crude oil and natural gas (including natural gas produced from shale plays like the Eagle Ford, Haynesville, Barnett, Marcellus and Utica Shales) incurred by our customers or could make it more difficult to perform hydraulic fracturing. If these legislative and regulatory initiatives cause a material decrease in the drilling of new wells and related servicing activities, it may affect the volume of hydrocarbon projects available to our midstream businesses and have a material adverse effect on our financial position, results of operations and cash flows.

See "Regulatory Matters" under Part I, Item 1 and 2 of this annual report for more information and specific disclosures relating to environmental, health and safety laws and regulations, and costs and liabilities.

Federal, state or local regulatory measures could have a material adverse effect on our financial position, results of operations and cash flows.

The FERC regulates our interstate liquids pipelines under the ICA. State regulatory agencies regulate our intrastate natural gas and NGL pipelines, intrastate storage facilities and gathering lines.

Our intrastate NGL and natural gas pipelines are subject to regulation in many states, including Colorado, Kansas, Louisiana, New Mexico, Texas and Wyoming. To the extent our intrastate natural gas pipelines engage in interstate transportation, they are also subject to regulation by the FERC pursuant to Section 311 of the NGPA. We also have natural gas underground storage facilities in Louisiana and Texas. Although state regulation is typically less comprehensive in scope than regulation by the FERC, our services are typically required to be provided on a nondiscriminatory basis and are also subject to challenge by protest and complaint.

Although our natural gas gathering systems are generally exempt from FERC regulation under the NGA, our natural gas gathering operations could be adversely affected should they become subject to federal regulation of rates and services, or, if the states in which we operate adopt policies imposing more onerous regulation on gas gathering operations. Additional rules and legislation pertaining to these matters are considered and adopted from time to time at both state and federal levels. We cannot predict what effect, if any, such regulatory changes and legislation might have on our operations, but we could be required to incur additional capital expenditures.

For a general overview of federal, state and local regulation applicable to our assets, see "Regulatory Matters" included within Part I, Item 1 and 2 of this annual report. This regulatory oversight can affect certain aspects of our business and the market for our products and could have a material adverse effect on our financial position, results of operations and cash flows.

The rates of our regulated assets are subject to review and possible adjustment by federal and state regulators, which could adversely affect our revenues.

The FERC, pursuant to the ICA (as amended), the Energy Policy Act and rules and orders promulgated thereunder, regulates the tariff rates for our interstate common carrier liquids pipeline operations. To be lawful under the ICA, interstate tariff rates, terms and conditions of service must be just and reasonable and not unduly discriminatory, and must be on file with the FERC. In addition, pipelines may not confer any undue preference upon any shipper. Shippers may protest (and the FERC may investigate) the lawfulness of new or changed tariff rates. The FERC can suspend those tariff rates for up to seven months. It can also require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful and prescribe new rates prospectively. The FERC and interested parties can also challenge tariff rates that have become final and effective. The FERC can also order new rates to take effect prospectively and order reparations for past rates that exceed the just and reasonable level up to two years prior to the date of a complaint. Due to the complexity of rate making, the lawfulness of any rate is never assured. A successful challenge of our rates could adversely affect our revenues.

The FERC uses prescribed rate methodologies for approving regulated tariff rate changes for interstate liquids pipelines. The FERC's indexing methodology currently allows a pipeline to increase its rates by a percentage linked to the PPI. However, in any year in which the index is negative, a pipeline must file to lower its rates if its rates would be above the indexed rate ceiling. As an alternative to this indexing methodology, we may also choose to support our rates based on a cost-of-service methodology, or by obtaining advance approval to charge "market-based rates," or by charging "settlement rates" agreed to by all affected shippers. These methodologies may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting increased costs.

The FERC issued an advance notice of proposed rulemaking seeking comment regarding potential modifications to its policies for evaluating oil pipeline indexed rate changes and to the reporting requirements. The FERC observed that some pipelines continue to obtain additional index rate increases despite reporting on Form No. 6 that their revenues exceed their costs. The FERC is proposing a new policy that would deny proposed index increases if a pipeline's Form No. 6 reflects revenues exceeding total cost of service by 15% for both of the prior two years or the proposed index increases exceed by 5% the annual cost changes reported by the pipeline. In addition, the FERC issued an NOI, to develop a mechanism to demonstrate there is no double recovery of partnership income tax costs. Changes in the FERC's approved methodology for approving rates, or challenges to our application of that methodology, could adversely affect us. Adverse decisions by the FERC in approving our regulated rates could adversely affect our cash flow.

The intrastate liquids pipeline transportation services we provide are subject to various state laws and regulations that apply to the rates we charge and the terms and conditions of the services we offer. Although state regulation typically is less onerous than FERC regulation, the rates we charge and the provision of our services may be subject to challenge.

<u>The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.</u>

The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted in 2010 (the "Dodd-Frank Act") provides for statutory and regulatory requirements for swaps and other derivative transactions, including financial and certain physical oil and gas hedging transactions. Under the Dodd-Frank Act, the CFTC has adopted regulations requiring registration of swap dealers and major swap participants, mandatory clearing of swaps, election of the end-user exception for any uncleared swaps by certain qualified companies, recordkeeping and reporting requirements, business conduct standards and position limits among other requirements. Several of these requirements, including position limits rules, allow the CFTC to impose controls that could have an adverse impact on our ability to hedge risks associated with our business and could increase our working capital requirements to conduct these activities.

Based on an assessment of final rules promulgated by the CFTC, we have determined that we are not a swap dealer, major swap participant or a financial entity, and therefore have determined that we currently qualify as an end-user. In addition, the vast majority of our derivative transactions are currently transacted through a Derivatives Clearing Organization, and we believe our use of the end-user exception will likely not be necessary on a routine basis. We will also seek to retain our status as an end-user by taking reasonable measures necessary to avoid becoming a swap dealer, major swap participant or financial entity and other measures to preserve our ability to elect the end-user exception should it become necessary. However, derivative transactions that are not clearable, and transactions that are clearable but for which we choose to elect the end-user exception, are subject to recordkeeping and reporting requirements and potentially additional credit support arrangements including cash margin or collateral. Posting of additional cash margin or collateral could affect our liquidity and reduce our ability to use cash for capital expenditures or other company purposes.

In September 2012, the U.S. District Court for the District of Columbia vacated and remanded the position limits rules adopted by the CFTC based on a necessity finding. In December 2013, the CFTC responded by proposing amended rules in an effort to better conform to the Dodd-Frank Act and in December 2016, the CFTC further refined and reproposed rules on position limits. Under the reproposed rules, the CFTC would place volumetric limitations on certain positions in 25 core physical commodity futures contracts and their economically equivalent futures, options and swaps. While we believe that the majority of our hedging transactions would meet one or more of the enumerated categories for Bona Fide Hedges, the rules could have an adverse impact on our ability to hedge certain risks associated with our business and could potentially affect our profitability. The CFTC has announced a 60-day period for public comment on the reproposed rules.

Over the past year, President Trump and the U.S. Congress have taken various actions suggesting some interest in amending some of the statutory and regulatory provisions impacting financial markets and institutions. The CFTC has a new Chairman and new Commissioners who may reevaluate some of the existing regulations and regulatory proposals. It is not clear at this time what, if any, changes in the law will be enacted or what, if any, changes in the existing regulations will be adopted, or how any such changes would impact our hedging activity.

<u>Our standalone operating cash flow is derived primarily from cash distributions we receive from EPO.</u>

On a standalone basis, Enterprise Products Partners L.P. is a holding company with no business operations and conducts all of its business through its wholly owned subsidiary, EPO. As a result, we depend upon the earnings and cash flows of EPO and its subsidiaries and joint ventures, and the distribution of their cash flows to us in order to meet our obligations and to allow us to make cash distributions to our limited partners.

The amount of cash EPO and its subsidiaries and joint ventures can distribute to us depends primarily on cash flows generated from their operations. These operating cash flows fluctuate based on, among other things, the: (i) volume of hydrocarbon products transported on their gathering and transmission pipelines; (ii) throughput volumes in their processing and treating operations; (iii) fees charged and the margins realized for their various storage, terminaling, processing and transportation services; (iv) price of natural gas, crude oil and NGLs; (v) relationships among natural gas, crude oil and NGL prices, including differentials between regional markets; (vi) fluctuations in their working capital needs; (vii) level of their operating costs; (viii) prevailing economic conditions; and (ix) level of competition encountered by their businesses. In addition, the actual amount of cash EPO and its subsidiaries and joint ventures will have available for distribution will depend on factors such as: (i) the level of sustaining capital expenditures incurred; (ii) their cash outlays for expansion (or growth) capital projects and acquisitions; and (iii) their debt service requirements and restrictions included in the provisions of existing and future indebtedness, organizational documents, applicable state business organization laws and other applicable laws and regulations. Because of these factors, we may not have sufficient available cash each quarter to continue paying distributions at our current levels.

Risks Relating to Our Partnership Structure

We may issue additional securities without the approval of our common unitholders.

At any time, we may issue an unlimited number of limited partner interests of any type (to parties other than our affiliates) without the approval of our unitholders. Our partnership agreement does not give our common unitholders the right to approve the issuance of equity securities, including equity securities ranking senior to our common units. The issuance of additional common units or other equity securities of equal or senior rank will have the following effects: (i) the ownership interest of a unitholder immediately prior to the issuance will decrease; (ii) the amount of cash available for distribution on each common unit may decrease; (iii) the ratio of taxable income to distributions may increase; (iv) the relative voting strength of each previously outstanding common unit may be diminished; and (v) the market price of our common units may decline.

We may not have sufficient operating cash flows to pay cash distributions at the current level following establishment of cash reserves and payments of fees and expenses.

Because cash distributions on our common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance and capital needs. We cannot guarantee that we will continue to pay distributions at the current level each quarter. The actual amount of cash that is available to be distributed each quarter will depend upon numerous factors, some of which are beyond our control and the control of our general partner. These factors include, but are not limited to: (i) the volume of the products that we handle and the prices we receive for our services; (ii) the level of our operating costs; (iii) the level of competition in our business; (iv) prevailing economic conditions, including the price of and demand for crude oil, natural gas, NGLs and other products we transport, store and market; (v) the level of capital expenditures we make; (vi) the amount and cost of capital we can raise compared to the amount of our capital expenditures and debt service requirements; (vii) restrictions contained in our debt agreements; (viii) fluctuations in our working capital needs; (ix) weather volatility; (x) cash outlays for acquisitions, if any; and (xi) the amount, if any, of cash reserves required by our general partner in its sole discretion.

Furthermore, the amount of cash that we have available for distribution is not solely a function of profitability, which will be affected by non-cash items such as depreciation, amortization and provisions for asset impairments. Our cash flows are also impacted by borrowings under credit agreements and similar arrangements. As a result, we may be able to make cash distributions during periods when we record losses and may not be able to make cash distributions during periods when we record net income. An inability on our part to pay cash distributions to partners could have a material adverse effect on our financial position, results of operations and cash flows.

<u>We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.</u>

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash, after taking into account reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our common units and other limited partner interests may decrease in correlation with any reduction in our cash distributions per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

<u>Our general partner and its affiliates have limited fiduciary responsibilities to, and conflicts of interest with respect to, our partnership, which may permit it to favor its own interests to your detriment.</u>

The directors and officers of our general partner and its affiliates have duties to manage our general partner in a manner that is beneficial to its members. At the same time, our general partner has duties to manage our partnership in a manner that is beneficial to us. Therefore, our general partner's duties to us may conflict with the duties of its officers and directors to its members. Such conflicts may include, among others, the following:

- neither our partnership agreement nor any other agreement requires our general partner or EPCO to pursue a business strategy that favors us;

- decisions of our general partner regarding the amount and timing of asset purchases and sales, cash expenditures, borrowings, issuances of additional units, and the establishment of additional reserves in any quarter may affect the level of cash available to pay quarterly distributions to our unitholders;

- under our partnership agreement, our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

- our general partner is allowed to resolve any conflicts of interest involving us and our general partner and its affiliates, and may take into account the interests of parties other than us, such as EPCO, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;

- any resolution of a conflict of interest by our general partner not made in bad faith and that is fair and reasonable to us is binding on the partners and is not a breach of our partnership agreement;

- affiliates of our general partner may compete with us in certain circumstances;

- our general partner has limited its liability and reduced its fiduciary duties and has also restricted the remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. As a result of purchasing our units, you are deemed to consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;

- we do not have any employees and we rely solely on employees of EPCO and its affiliates;

- in some instances, our general partner may cause us to borrow funds in order to permit the payment of distributions;

- our general partner may cause us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

- our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, may be entitled to be indemnified by us;

- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and

- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

We have significant business relationships with entities controlled by EPCO and Dan Duncan LLC. For information regarding these relationships and related party transactions with EPCO and its affiliates, see Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report. Additional information regarding our relationship with EPCO and its affiliates can also be found under Part III, Item 13 of this annual report.

The NYSE does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

We currently list our common units on the NYSE under the symbol "EPD." Because we are a publicly traded limited partnership, the NYSE does not require us to have a majority of independent directors on our general partner's Board or to establish a compensation committee or a nominating and corporate governance committee. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the NYSE's shareholder approval rules that apply to a corporation. Accordingly, unitholders do not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements. See Part III, Item 10 of this annual report for additional information.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors. In addition, even if unitholders are dissatisfied, they cannot easily remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis. The owners of our general partner choose the directors of our general partner.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have no practical ability to remove our general partner or its officers or directors. Our general partner may not be removed except upon the vote of the holders of at least 60% of our outstanding units voting together as a single class. Since affiliates of our general partner currently own approximately 32% of our outstanding common units, the removal of Enterprise GP as our general partner is highly unlikely without the consent of both our general partner and its affiliates. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence of a takeover premium in the trading price.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by a provision in our partnership agreement stating that any units held by a person that owns 20% or more of any class of our common units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence our management. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence of a takeover premium in the trading price.

Our general partner has a limited call right that may require common unitholders to sell their common units at an undesirable time or price.

If at any time our general partner and its affiliates own 85% or more of the common units then outstanding, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price not less than the then current market price. As a result, common unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. Unitholders may also incur a tax liability upon the sale of their common units.

Our common unitholders may not have limited liability if a court finds that limited partner actions constitute control of our business.

Under Delaware law, common unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right of limited partners to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business. Under Delaware law, our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those of our contractual obligations that are expressly made without recourse to our general partner.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. You could have unlimited liability for our obligations if a court or government agency determined that (i) we were conducting business in a state, but had not complied with that particular state's partnership statute; or (ii) your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constituted "control" of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, our unitholders may have to repay amounts wrongfully distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

Our general partner's interest in us and the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner, in accordance with our partnership agreement, may transfer its general partner interest without the consent of unitholders. In addition, our general partner may transfer its general partner interest to a third party in a merger or consolidation or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the sole member of our general partner, currently Dan Duncan LLC, to transfer its equity interests in our general partner to a third party. The new equity owner of our general partner would then be in a position to replace the Board and officers of our general partner with their own choices and to influence the decisions taken by the Board and officers of our general partner.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation for federal income tax purposes or if we were otherwise subject to a material amount of entity-level taxation, then cash available for distribution to our unitholders would be reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, we will be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based on our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service ("IRS") with respect to our classification as a partnership for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate and we would also likely pay additional state and local income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to our unitholders would be reduced. Thus, treatment of us as a corporation could result in a reduction in the anticipated cash-flow and after-tax return to our unitholders, likely causing a reduction in the value of our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, capital, and other forms of business taxes as well as subjecting nonresident partners to taxation through the imposition of withholding obligations and composite, combined, group, block, or similar filing obligations on nonresident partners receiving a distributive share of state "sourced" income. We currently own property or do business in a substantial number of states. Imposition on us of any of these taxes in jurisdictions in which we own assets or conduct business or an increase in the existing tax rates could substantially reduce the cash available for distribution to our unitholders.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships or an investment in our common units.

Further, final Treasury Regulations under Section 7704(d)(1)(E) of the Internal Revenue Code recently published in the Federal Register interpret the scope of qualifying income requirements for publicly traded partnerships by providing industry-specific guidance. We do not believe the final Treasury Regulations affect our ability to be treated as a partnership for federal income tax purposes.

In addition, the Tax Cuts and Jobs Act (the "Tax Act") enacted December 22, 2017, makes significant changes to the federal income tax rules applicable to both individuals and entities, including changes to the effective tax rate on an individual or other non-corporate unitholder's allocable share of certain income from a publicly traded partnership. The Tax Act is complex and lacks administrative guidance, thus, unitholders should consult their tax advisor regarding the Tax Act and its effect on an investment in our common units.

Any changes to federal income tax laws and interpretations thereof (including administrative guidance relating to the Tax Act) may or may not be applied retroactively and could make it more difficult or impossible for us to be treated as a partnership for federal income tax purposes or otherwise adversely affect our business, financial condition or results of operations. Any such changes or interpretations thereof could adversely impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of the units on the first day of each month, instead of on the basis of the date a particular unit is transferred. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units and the cost of any IRS contest will reduce our cash available for distribution to unitholders.

The IRS has made no determination as to our status as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the positions we take, even positions taken with advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of the positions we take. As a result, any such contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, our costs of any contest with the IRS, principally legal, accounting and related fees, will be indirectly borne by our unitholders because the costs will reduce our cash available for distribution.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case we may elect to either pay the taxes directly to the IRS or to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes. If we bear such payment our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised Schedule K-1 to each unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own common units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced.

Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount from the cash that we distribute, our unitholders may be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive any cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from their share of our taxable income.

Tax gains or losses on the disposition of our common units could be more or less than expected.

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in the unitholder's common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if the unitholder sells such common units at a price greater than the unitholder's tax basis in those common units, even if the price received is less than the unitholder's original cost. A substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized may include a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of the cash received from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investments in our common units by tax-exempt entities, such as individual retirement accounts ("IRAs") or other retirement plans, and non-U.S. persons raise issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. Additionally, gain recognized by a non-U.S. person on the sale of common units occurring on or after November 27, 2017, will generally be treated as effectively connected income and subject to U.S. federal income tax. Although sales of common units by non-U.S. persons occurring after December 31, 2017, are also subject to withholding taxes under the Tax Act, Notice 2018-08 provides that withholding is not required with respect to such sales until regulations or other guidance has been issued by the IRS. A unitholder that is a tax-exempt entity or a non-U.S. person should consult a tax advisor before investing in our common units.

We treat each purchaser of our common units as having the same tax benefits without regard to the common units purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a common unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the unitholder's tax returns.

Our common unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes imposed by the various jurisdictions in which we do business or own property now or in the future, even if the unitholder does not live in any of those jurisdictions. Our common unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property or conduct business in a substantial number of states, many of which impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal or corporate income tax. It is the responsibility of each unitholder to file its own federal, state and local tax returns, as applicable.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from lending their common units.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our respective assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the amount, character, and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Item 1B. *Unresolved SEC Staff Comments.*

None.

Item 3. *Legal Proceedings.*

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. Except as set forth below, we are not aware of any material pending legal proceedings as of the filing date of this annual report to which we are a party, other than routine litigation incidental to our business.

ETP Matter

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

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

We filed our Brief of the Appellant in the Court of Appeals for the Fifth District of Dallas, Texas on March 30, 2015 and ETP filed its Brief of Appellees on June 29, 2015. We filed our Reply Brief of Appellant on September 18, 2015. Oral argument was conducted on April 20, 2016, and the case was then submitted to the Court of Appeals for its consideration. On July 18, 2017, a panel of the Court of Appeals issued a unanimous opinion reversing the trial court's judgment as to all of ETP's claims against Enterprise, rendering judgment that ETP take nothing on those claims, and affirming Enterprise's counterclaim against ETP of approximately $0.8 million, plus interest.

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. As of December 31, 2017, we have not recorded a provision for this matter as management continues to believe that payment of damages by us in this case is not probable. We continue to monitor developments involving this matter.

PDH Litigation

In July 2013, we executed a contract with Foster Wheeler USA Corporation ("Foster Wheeler") pursuant to which Foster Wheeler was to serve as the general contractor responsible for the engineering, procurement, construction and installation of our 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 ("OPD"), 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.

Environmental Matters

On occasion, we are assessed monetary sanctions by governmental authorities related to administrative or judicial proceedings involving environmental matters. We do not expect such expenditures to be material to our consolidated financial statements.

- In January 2015, the Attorney General of Texas filed litigation against us for CAA violations resulting from the February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. Resolution of these matters is expected to result in monetary sanctions in excess of $0.1 million.

- In December 2017, we received a Notice of Enforcement from the Texas Commission on Environmental Quality associated with historical self-disclosed violations that occurred at our Mont Belvieu complex. The eventual resolution of these matters may result in monetary sanctions in excess of $0.1 million.

Item 4. *Mine Safety Disclosures.*

Not applicable.

PART II

Item 5. *Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities.*

Our common units are listed on the NYSE under the ticker symbol "EPD." As of January 31, 2018, there were approximately 2,650 unitholders of record of our common units. The following table presents high and low sales prices for our common units for the periods presented (as reported by the NYSE Composite ticker tape) and the amount, record date and payment date of the quarterly cash distributions we paid on each of our common units with respect to such periods.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2015					
1st Quarter	$36.98	$30.71	$0.3750	04/30/15	05/07/15
2nd Quarter	$34.73	$29.53	$0.3800	07/31/15	08/07/15
3rd Quarter	$31.17	$22.01	$0.3850	10/30/15	11/06/15
4th Quarter	$29.02	$20.76	$0.3900	01/29/16	02/05/16
2016					
1st Quarter	$26.70	$19.00	$0.3950	04/29/16	05/06/16
2nd Quarter	$29.43	$23.56	$0.4000	07/29/16	08/05/16
3rd Quarter	$30.11	$25.76	$0.4050	10/31/16	11/07/16
4th Quarter	$27.80	$24.01	$0.4100	01/31/17	02/07/17
2017					
1st Quarter	$30.25	$26.70	$0.4150	04/28/17	05/08/17
2nd Quarter	$28.26	$25.78	$0.4200	07/31/17	08/07/17
3rd Quarter	$27.93	$24.84	$0.4225	10/31/17	11/07/17
4th Quarter	$26.87	$23.59	$0.4250	01/31/18	02/07/18

Actual cash distributions are paid by us within 45 days after the end of each fiscal quarter. We expect that our cash distributions will be funded primarily through cash provided by operating activities. Although the payment of cash distributions is not guaranteed, we believe that our operations will continue to generate cash sufficient to pay distributions in the foreseeable future at levels comparable to those presented in the preceding table.

For additional information regarding our cash distributions to partners, see Note 9 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Recent Issuance of Unregistered Securities

There were no sales of unregistered equity securities during 2017.

Common Units Authorized for Issuance Under Equity Compensation Plan

See "Securities Authorized for Issuance Under Equity Compensation Plans" included under Part III, Item 12 of this annual report, which is incorporated by reference into this Item 5.

Issuer Purchases of Equity Securities

A total of 3,166,624 unit-based awards (restricted common unit and phantom unit awards granted to key employees of EPCO) vested and were converted to common units during 2017. Of this amount, 229,910 were sold back to us by employees to meet their tax withholding requirements in connection with the vesting of restricted common unit awards. In addition, 797,888 were sold back to us by employees to meet their tax withholding requirements in connection with the vesting of phantom unit awards. The total cost of these repurchased units was $29.5 million. We cancelled such treasury units immediately upon acquisition.

The following table summarizes our repurchase activity during 2017 in connection with these vesting transactions:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
Vesting of restricted common unit awards:				
February 2017 (1)	225,751	$ 28.77	--	--
May 2017 (2)	742	$ 27.45	--	--
August 2017 (3)	3,026	$ 26.58	--	--
November 2017 (4)	391	$ 25.11	--	--
Vesting of phantom unit awards:				
February 2017 (5)	720,393	$ 28.82	--	--
March 2017 (6)	147	$ 27.58	--	--
May 2017 (7)	39,653	$ 27.40	--	--
August 2017 (8)	17,003	$ 27.00	--	--
November 2017 (9)	20,692	$ 25.17	--	--

(1) Of the 665,920 restricted common unit awards that vested in February 2017 and converted to common units, 225,751 units were sold back to us by employees to cover related withholding tax requirements.
(2) Of the 2,550 restricted common unit awards that vested in May 2017 and converted to common units, 742 units were sold back to us by employees to cover related withholding tax requirements.
(3) Of the 10,900 restricted common unit awards that vested in August 2017 and converted to common units, 3,026 units were sold back to us by employees to cover related withholding tax requirements.
(4) Of the 1,674 restricted common unit awards that vested in November 2017 and converted to common units, 391 units were sold back to us by employees to cover related withholding tax requirements.
(5) Of the 2,233,617 phantom unit awards that vested in February 2017 and converted to common units, 720,393 units were sold back to us by employees to cover related withholding tax requirements.
(6) Of the 450 phantom unit awards that vested in March 2017 and converted to common units, 147 units were sold back to us by employees to cover related withholding tax requirements.
(7) Of the 117,369 phantom unit awards that vested in May 2017 and converted to common units, 39,653 units were sold back to us by employees to cover related withholding tax requirements.
(8) Of the 61,634 phantom unit awards that vested in August 2017 and converted to common units, 17,003 units were sold back to us by employees to cover related withholding tax requirements.
(9) Of the 72,510 phantom unit awards that vested in November 2017 and converted to common units, 20,692 units were sold back to us by employees to cover related withholding tax requirements.

In December 1998, we announced a common unit repurchase program whereby we, together with certain affiliates, could repurchase up to 4,000,000 of our common units on the open market. A total of 2,763,200 common units were repurchased under this program; however, no repurchases have been made since 2002. As of December 31, 2017, we and our affiliates could repurchase up to 1,236,800 additional common units under this program.

Item 6. ***Selected Financial Data.***

The following table presents selected historical consolidated financial data of our partnership. This information has been derived from and should be read in conjunction with our audited financial statements included under Part II, Item 8 of this annual report, which presents our audited balance sheets as of December 31, 2017 and 2016 and related statements of consolidated operations, comprehensive income, cash flows and equity for the three years ended December 31, 2017, 2016 and 2015, respectively. As presented in the table, amounts are in millions (except per unit data).

	For the Year Ended December 31,				
	2017	2016	2015	2014	2013
Statements of operations data:					
Total revenues	$ 29,241.5	$ 23,022.3	$ 27,027.9	$ 47,951.2	$ 47,727.0
Cost of sales	21,487.0	15,710.9	19,612.9	40,464.1	40,770.2
Other costs and expenses	4,251.6	4,092.7	4,248.4	3,970.9	3,656.8
Equity in income of unconsolidated affiliates	426.0	362.0	373.6	259.5	167.3
Operating income	3,928.9	3,580.7	3,540.2	3,775.7	3,467.3
Interest expense	984.6	982.6	961.8	921.0	802.5
Net income	2,855.6	2,553.0	2,558.4	2,833.5	2,607.1
Net income attributable to noncontrolling interests	56.3	39.9	37.2	46.1	10.2
Net income attributable to limited partners	2,799.3	2,513.1	2,521.2	2,787.4	2,596.9
Earnings per unit:					
Basic ($/unit)	1.30	1.20	1.28	1.51	1.45
Diluted ($/unit)	1.30	1.20	1.26	1.47	1.41
Cash distributions paid with respect to period ($/unit)	1.6825	1.6100	1.5300	1.4500	1.3700

	As of December 31,				
	2017	2016	2015	2014	2013
Balance sheet data:					
Property, plant and equipment, net	$ 35,620.4	$ 33,292.5	$ 32,034.7	$ 29,881.6	$ 26,946.6
Investments in unconsolidated affiliates	2,659.4	2,677.3	2,628.5	3,042.0	2,437.1
Total assets	54,418.1	52,194.0	48,802.2	47,057.7	40,025.5
Long-term debt, including current maturities	24,568.7	23,697.7	22,540.8	21,220.5	17,238.3
Total liabilities	31,645.7	29,928.0	28,301.1	27,365.5	24,585.1
Equity:					
Partners' equity	$ 22,547.2	$ 22,047.0	$ 20,295.1	$ 18,063.2	$ 15,214.8
Noncontrolling interests	225.2	219.0	206.0	1,629.0	225.6
Total equity	$ 22,772.4	$ 22,266.0	$ 20,501.1	$ 19,692.2	$ 15,440.4
Limited partner units outstanding (millions)	2,161.1	2,117.6	2,012.6	1,937.3	1,871.4

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. For additional information regarding energy commodity prices, see "Selected Energy Commodity Price Data" included under Part II, Item 7 of this annual report. General information regarding our results of operations can also be found under Part II, Item 7 of this annual report.

Property, plant and equipment balances increased in each of the years presented due to our ongoing capital expenditure program, which includes business combinations such as EFS Midstream and Oiltanking. For information regarding our capital spending program, see "Capital Spending" included under Part II, Item 7 of this annual report. For information regarding our recent business combinations, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Investments in unconsolidated affiliates decreased in 2015 primarily due to the sale of our Offshore Business, which included a number of pipeline and platform joint ventures operating in the Gulf of Mexico. See Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for additional information regarding the sale of this business.

Our debt balances, including related interest expense, increased in each of the years presented primarily due to the funding of a portion of our capital spending program using borrowings under bank credit agreements and the issuance of short- and long-term notes. For information regarding our debt balances, see Note 8 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Our equity balances, along with the number of common units outstanding, increased in each of the years presented due to the issuance of units in connection with business combinations and the sale of units under our at-the-market program, distribution reinvestment plan and employee unit purchase plan. Net proceeds generated from the sale of common units were primarily used to fund a portion of our capital spending program.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations.***

For the Years Ended December 31, 2017, 2016 and 2015

The following information should be read in conjunction with our Consolidated Financial Statements and accompanying notes included under Part II, Item 8 of this annual report. 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 December 31, 2017.

References to "EFS Midstream" mean EFS Midstream LLC, which we acquired in July 2015 from affiliates of Pioneer Natural Resources Company ("PXD") and Reliance Industries Limited ("Reliance"). See Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding this acquisition.

References to "Offshore Business" refer to the Gulf of Mexico operations we sold to Genesis Energy, L.P. in July 2015. See Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding this sale.

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

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

Cautionary Statement Regarding Forward-Looking Information

This annual report on Form 10-K for the year ended December 31, 2017 (our "annual report") 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 this annual 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 annual 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 United States ("U.S."), Canada and the Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations currently include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and export and import terminals (including those used to export liquefied petroleum gases, or "LPG," and ethane); crude oil gathering, transportation, storage, and export and import terminals; petrochemical and refined products transportation, storage, export and import terminals, and related services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems. Our assets currently include approximately 50,000 miles of pipelines; 260 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.

Significant Recent Developments

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 expected redemption of all $682.7 million outstanding aggregate principal amount of its 7.034% Junior Subordinated Notes B (the "7.034% Notes").

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.

The redemption of the 7.034% Notes and the issuance of the 5.375% Junior Subordinated Notes F will result in annual interest savings to EPO of approximately $11.3 million. On February 1, 2018, EPO notified its trustee and paying agent to redeem all of the $682.7 million outstanding aggregate principal amount of its 7.034% Notes. EPO anticipates that the 7.034% Notes will be redeemed on or about March 5, 2018, in accordance with the terms of the 7.034% Notes, 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.

Plans to Build Ethylene Export Dock and Related Projects

In January 2018, we announced the formation of a new 50/50 joint venture with Navigator Holdings Ltd. ("Navigator") to construct, own and operate an ethylene export facility along the U.S. Gulf Coast. The export facility is expected to have the capacity to export approximately 1 million tons of ethylene per year, with loading rates of approximately 1,000 tons per hour. In addition, the facility is expected to include refrigerated storage for 30,000 tons of ethylene. The project, which is underwritten by long-term contracts with customers, is expected to be completed in the first quarter of 2020. The location and final investment decisions for the terminal are subject to reaching acceptable arrangements with local taxing authorities.

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

Further supporting our ethylene capabilities, we also plan to build a 24-mile, 12-inch or larger diameter ethylene pipeline extending from Mont Belvieu to Bayport, Texas. The new pipeline would have the potential to connect both producing and consuming customers located south of the Houston Ship Channel to our facility in Mont Belvieu.

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.

Enterprise to Expand Orla Natural Gas Processing Complex in West Texas
In January 2018, we announced plans to add 300 MMcf/d of incremental capacity at our cryogenic natural gas processing facility under construction near Orla, Texas in Reeves County. The addition of a third processing train at Orla ("Orla III") would increase inlet volume capacity to 900 MMcf/d and allow us to expand our NGL extraction capabilities by an incremental 40 MBPD to 120 MBPD. Orla III is expected to begin service in the third quarter of 2019.

In June 2017, we announced plans to add a second processing train ("Orla II") to our cryogenic natural gas processing facility currently under construction near Orla, Texas in Reeves County. Orla II is expected to add 300 MMcf/d of incremental processing capacity to the facility and double the inlet capacity of the facility to 600 MMcf/d and increase extraction of NGLs from up to 40 MBPD to up to 80 MBPD. Orla II is expected to begin service in the fourth quarter of 2018.

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

Enterprise Management Provides Guidance with Regards to Distribution Growth through 2018
In October 2017, our management announced plans to recommend to the Board cash distribution increases per quarter of \$0.0025 per unit with respect to each of the six fiscal quarters beginning with the third quarter of 2017 and ending with the fourth quarter of 2018. The Board declared a \$0.4225 per common unit cash distribution to limited partners with respect to the third quarter of 2017, which was paid on November 7, 2017. The Board declared a \$0.425 per common unit cash distribution to limited partners with respect to the fourth quarter of 2017, which was paid on February 7, 2018. Management currently expects to recommend to the Board the following quarterly cash distributions with respect to each quarter of 2018: \$0.4275, first quarter of 2018; \$0.4300, second quarter of 2018; \$0.4325, third quarter of 2018; and \$0.4350, fourth quarter of 2018.

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

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

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

Completion of Azure Acquisition
In April 2017, we closed on the acquisition of a midstream energy business from Azure Midstream Partners, LP and its operating subsidiaries (collectively, "Azure") for $191.4 million in cash. The acquired business assets, which are located primarily in East Texas, include over 750 miles of natural gas gathering pipelines and two natural gas processing facilities with an aggregate processing capacity of 130 MMcf/d. The acquired business serves production from the Haynesville Shale and Bossier, Cotton Valley and Travis Peak formations.

For additional information regarding the Azure acquisition, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

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

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

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

General Outlook for 2018

Commercial Outlook

<u>General Commodity Price Observations</u>

As a result of significant advances in non-conventional drilling and production technology, North American reserves and production of hydrocarbons, primarily from shale resource basins such as the Permian Basin in West Texas, the Eagle Ford in South Texas and the Appalachia Basin in the Northeast U.S., increased substantially in recent years. The significant increase in U.S. hydrocarbon supplies has led to lower prices, a reduction in imports, and, in many cases significantly increased exports; in fact, the U.S. is rapidly turning into a major exporter of various hydrocarbons including natural gas, NGLs, crude oil, petrochemicals and refined products.

In response to the growing supplies, beginning in November 2014, the Organization of Petroleum Exporting Countries ("OPEC"), opted to defend its market share by maintaining (and in some cases increasing) its crude oil production levels rather than their previous practice of cutting production to balance global markets. The result was bloated global inventories of crude oil and products and a dramatic decline in global crude oil prices from an average of $93 per barrel in 2014, to $49 per barrel in 2015 and further to $43 per barrel in 2016, as measured by the price of West Texas Intermediate ("WTI"). Prices reached a low of approximately $26 per barrel in February 2016. In September 2016, as a result of continued negative market sentiment on crude oil prices, OPEC members began discussing an output "freeze" to try to balance global markets and reduce excess crude oil inventories. In November 2016, OPEC members formally agreed to production cuts, starting January 1, 2017, that have significantly reduced the global crude oil supply overhang. As of the end of November 2017, oil stocks in the 35 member countries comprising the Organisation for Economic Co-Operation and Development (or "OECD") decreased by an aggregate 35 million barrels (or 3%) when compared to data from the end of 2016. Likewise, total refined products stocks in OECD countries decreased by 62 million (or 4%) when compared to data from year-end 2016.

OPEC members met again in December 2017 and agreed to extend the freeze into 2018, and are expected to meet again in the summer of 2018 to review market conditions and the impact of the freeze on global balances. In addition to OPEC members, certain non-OPEC producers including Russia have agreed to participate in the production cuts, which has further strengthened crude oil and related energy commodity prices. As a general rule, there has been a high level of compliance with the OPEC production quotas and global inventories of crude oil and related products have fallen significantly. In addition to the OPEC-led production cuts, most industry experts expect that strong consumer demand for energy and related products due to the lower prices (combined with routine supply disruptions) will accelerate rebalancing of the global oil market, with daily demand exceeding supply as early as the second half of 2018. With the announced cuts and positive supply and demand trends, industry experts estimate that WTI prices will average $50 to $60 per barrel between now and 2020.

Likewise, natural gas prices have also experienced significant weakness in recent years as a result of excess domestic supplies and warmer than average winters. As measured by the NYMEX at Henry Hub, natural gas prices averaged $4.26 per MMBtu in 2014, $2.63 per MMBtu in 2015, $2.55 per MMBtu in 2016 and $3.02 per MMBtu in 2017. For the start of 2018, natural gas prices at Henry Hub averaged $3.00 per MMBtu through mid-February 2018.

In response to lower energy commodity prices, domestic producers significantly reduced both their drilling and completion activities in most production basins starting in early 2015. As a result of reduced drilling, domestic crude oil production at the end of 2016 was 840 MBPD lower than its previous peak in June 2015; however, with improved prices in 2017 and significant technical and efficiency gains, production of crude oil, NGLs and natural gas has been steadily increasing and, in fact, is at record production levels. As a result of higher energy commodity prices in 2017 and continued positive sentiment towards price stability, we expect an increase in producer investment and drilling and well completion activities during 2018 in and around our assets in the Permian, Eagle Ford, Haynesville and Rockies regions. Furthermore, we expect that our assets in these areas will be very competitive in supplying services for the resulting new production. We also believe that basins located closest to prime markets on the U.S. Gulf Coast will be preferred by producers due to more favorable economics as compared to other more distant areas (mostly due to lower transportation costs).

Supply Side Observations

During 2017, we saw a continuation of the upstream industry's shift to shale resource basins, away from long lead-time projects. Even the major oil companies shifted their investments towards the shale plays. We believe that because projects in U.S. shale resource basins exhibit a low risk, short lead time production profile, the U.S. shale resources will continue to play an increasing role in both domestic and global markets. Many energy economists also believe that outside of some limited excess production capacity within OPEC, U.S. shale production is now the world's swing crude oil supply.

Crude oil, natural gas and NGL prices were significantly higher in 2017, compared to 2016 and 2015, although far below peak levels seen in 2014. Nonetheless, U.S. exploration and production ("E&P") companies have shown that they can grow shale production at a crude oil price of $50/bbl. Oilfield service and E&P companies continue to improve technologies to drill and complete non-conventional wells more efficiently. Some of these improvements include faster drilling, longer horizontal laterals, and higher density fracture treatments. Improved technology has enabled E&P companies to realize higher returns on capital from developing non-conventional resources at lower energy prices.

Rig counts increased rapidly in the first half of 2017. As more wells were drilled, most basins experienced a shortage of completion equipment and crews, forcing producers to defer completions and build their inventory of drilled but uncompleted wells ("DUCs"). The DUC count grew by over 2,000 wells from December 2016 to December 2017, to a total of nearly 7,500 wells, as reported by the U.S. Energy Information Administration. This represents a significant potential volume which we believe could be brought into production starting in 2018. NGL volumes will likely grow proportionately faster than either crude oil or natural gas volumes, as the mix of drilling has continued to shift to crude oil wells and richer natural gas wells.

While changes in drilling rig counts (as reported by Baker Hughes) have historically been a reliable leading indicator of future production growth or decline, recent developments in technology, high grading of drilling locations and the large inventory of DUCs have reduced the correlation between changes in rig counts and changes in production. We believe this to be especially true when comparing current rig counts to those prior to 2015. Rig counts continue, however, to be a reliable indicator of overall E&P activity and investment.

U.S. E&P company sentiment continued to improve in 2017 as the OPEC production freeze had a high level of compliance and storage levels indicated a return to global supply-demand balance. Since May 2016, total U.S. drilling rig counts have increased by 542 rigs, or 134%, to 946 rigs as of February 2018. The crude oil rig count increased by 449 to 765 rigs, an increase of 142% from the low in May 2016. Likewise, the natural gas rig count increased by 100 rigs, or 123%, from the low in August 2016. Not all regions have reacted equally to the recovery in rig counts, with the largest increases seen in the Permian Basin and SCOOP/STACK play in Oklahoma. In the second half of 2017, rig count growth stabilized, however, we believe the current rig count is enough to continue to grow production, even without completion of a significant number of DUCs or further increases in productivity.

Permian Outlook

The Permian Basin in West Texas and southeastern New Mexico has experienced the largest increase in drilling activity in the country, with the number of active rigs increasing from 134 in April 2016 to 427 in February 2018. The Permian Basin is an oil prone basin with many attributes, including stacked pay zones, light sweet crude oil and a long history of support for the oil and gas industry. The current level of producer activity provides support for the construction of incremental midstream infrastructure in the basin. An area of focus for us has been the development of midstream infrastructure serving producers in the Delaware Basin, which is part of the overall Permian Basin. The Delaware Basin historically has been a relatively lightly drilled area due to a lack of conventional targets. With the introduction of horizontal drilling and identification of stacked targets of tight-rock and shales, Delaware Basin drilling has accelerated over the past five years. These drilling targets have proven to produce not only light crude oil but also lighter and gassier hydrocarbons such as condensate and NGLs. These gassier hydrocarbons have presented to us a large number of midstream opportunities to provide services to producers in the Delaware Basin. We are diligently working to identify attractive midstream prospects from these opportunities to complement our current asset infrastructure.

During 2017, we completed and placed into service two natural gas processing facilities (South Eddy and Waha) and are constructing three additional plants near Orla, Texas in the Delaware Basin. Two of the Orla plants (Orla I and II) are expected to start up in 2018 and one (Orla III) in 2019. When the Orla plants are completed we will operate approximately 1.3 Bcf/d of processing in the Permian Basin, which are all highly integrated with other Enterprise natural gas and NGL assets, including our Shin Oak NGL pipeline that is currently under construction. In addition, we placed into limited service a major crude oil pipeline system, the Midland-to-ECHO Pipeline System that serves producers in the Permian Basin and originates at our Midland, Texas crude oil terminal and extends to our Sealy, Texas terminal and on to our ECHO terminal near Houston, Texas. We are also evaluating several other natural gas, NGL and crude oil projects in the Permian Basin.

Eagle Ford outlook

Rig counts in the Eagle Ford shale region were significantly impacted by the downturn in crude oil prices and producers allocating their capital budgets to other producing basins, especially the Permian. With that being said, the number of active drilling rigs in the Eagle Ford shale has increased by 37 rigs, or 128%, to 66 rigs in February 2018 from the low recorded in May 2016. The historical peak for Eagle Ford Region crude oil and natural gas production occurred in March 2015 and was 1.7 MMBPD and 7.4 Bcf/d, respectively. According to the EIA Drilling Productivity Report, the most recent data (January 2018) for Eagle Ford Region production was 1.2 MMBPD of crude oil and 6.4 Bcf/d of natural gas. Until volumes for the Eagle Ford return to near historical peak production, there will be excess capacity in terms of midstream infrastructure available in the region. We believe that the Eagle Ford offers producers some of the best returns on capital of any region in the country and is also favorably situated near growing consumption and export markets on the U.S. Gulf Coast. Several large parcels of producing acreage have changed hands in recent years, which has resulted in a number of rigs being put back into service since the new owners are eager to begin realizing cash flows from their investments. We believe further ownership changes will take place in the near future that will increase the number of rigs working in the Eagle Ford, which could result in higher volumes for our assets.

Haynesville Outlook

The rig count in the Haynesville shale has grown in 2017 as a result of increased public and private equity investment in the region. We have seen several significant changes in the ownership of producing properties over the past year, which has led to increased drilling activity in the region by the new owners. From the low of 11 rigs recorded in February 2016, the Haynesville rig count has increased by 36 rigs, or 327%, to 47 rigs in February 2018. Drilling in the Haynesville has additionally benefitted from advances in drilling and completion technology (increased well lateral length, adding more fracking stages, significantly increased proppant concentration) resulting in improved natural gas recoveries per well and increased returns on capital for producers. The historical peak for the Haynesville region natural gas production occurred in November 2011 and was over 10.6 Bcf/d. According to the most recent EIA drilling Productivity Report (January 2018), the Haynesville Region natural gas production was 7.7 Bcf/d. In 2016, the U.S. Geological Survey estimated that the Haynesville and associated Bossier shale plays hold a combined 304 trillion cubic feet of technically recoverable shale gas resources, the second highest level in the U.S. after the Appalachia region. In addition, the Haynesville benefits from its close proximity to the Gulf Coast where substantial petrochemical and liquefied natural gas, or LNG, export buildout is underway. With natural gas futures prices currently at approximately $3.00 per MMBtu, we anticipate Haynesville gas production will continue growing. Until Haynesville volumes return to near historical peak production, there is generally excess capacity of midstream infrastructure available in the region.

Rockies Outlook

Rig counts have increased in the major basins of the Rockies. Drilling activity in the Piceance Basin increased from two rigs in May 2016 to eight rigs in February 2018, and in the Jonah and Pinedale fields increased from a combined four rigs in November 2016 to 12 rigs in February 2018. Drilling activity in the San Juan Basin increased from two rigs in November 2015 to three rigs in February 2018. The current level of drilling and completion activity in the Rockies is generally leading to growth in production of crude oil, natural gas and NGLs. In addition, early results from horizontal drilling in both Jonah and Pinedale fields are very promising for incremental natural gas and NGL production. The Rockies benefit from adequate natural gas and NGL pipeline infrastructure, which helps the region compete with other North American plays where takeaway capacity may be constrained. Like the Eagle Ford and Haynesville, we have seen several significant changes in the ownership of producing properties over the past year, which has led to increased drilling activity in the region by the new owners.

Demand Side Observations

Global demand for petroleum-based products continues to increase at rates that have generally exceeded economists' expectations, which is in large part due to improving economic growth worldwide. Due to higher crude oil prices and improved drilling and production techniques, U.S. crude oil production has bounced back and secured its place in the global supply. As a result, we expect that some of these new domestic barrels would supplant more of the U.S.'s crude oil imports while the remainder would be exported to growing international markets in Central and South America, Asia and Western Europe where the lighter U.S. crudes make good feedstocks for their refining facilities. We also expect U.S. refineries to operate at higher rates as a result of strong U.S. demand and growing exports of refined products.

We believe that our marine terminal assets and related infrastructure –storage and pipelines- are strategically located on the U.S. Gulf Coast to take advantage of the shift mentioned above: growing production resulting in reduced crude oil imports and higher exports of crude oil and refined products. These assets could benefit from concurrent imports and exports of various grades of crude oil as (i) refineries optimize their crude oil input slate, (ii) trading companies import and export different grades of crude oil depending on global and regional supply-demand factors, and (iii) producers optimize their production depending on market price signals.

Enterprise has significant crude oil export capabilities on the Houston Ship Channel and at Beaumont, Freeport and Texas City. Towards the end of 2017, we began limited service on the Midland-to-ECHO crude oil pipeline which will complement our existing assets and allow for the transportation, storage and export of segregated barrels, thus maintaining and assuring the quality and grade of the final product. This is in contrast to an operation relying on mixed streams of various oil qualities and grades. However, this outlook could be muted if there is a prolonged decline in domestic crude oil production or if overseas crude markets become oversupplied for an extended period.

We expect demand for ethane to grow further as several new world-scale ethylene plants begin operations in the U.S. through the early 2020s, which in turn could drive upstream NGL production increases. We also expect continued increase in global demand for heavier NGLs (butanes and natural gasoline) supported by rising global economic activity. With respect to natural gas demand, we expect it to continue to increase in the form of U.S. power generation demand, growing industrial demand, exports to Mexico and as LNG. We believe U.S. producers can provide ample supplies of natural gas at very competitive prices to meet growing global demand.

In recent years, U.S. natural gas and NGLs developed a feedstock price advantage over more costly crude oil derivatives (such as naphtha and gasoil). In general, we expect this trend to continue due to: (i) competitive domestic production from low risk, short lead time shale resource plays; (ii) the ability of U.S. producers and their suppliers to harness technology to keep costs down; (iii) anticipated long-term increases in demand for crude oil by developing economies; and (iv) ongoing geopolitical risks and poor rule of law in many countries that are major exporters of crude oil. These advantages lend themselves to a variety of long-term demand-side opportunities, including higher demand from the U.S. petrochemical industry and increased exports of various hydrocarbons (e.g., LNG, LPG, ethane and crude oil).

We also believe the trend in the feedstock price advantage of domestically-produced NGLs and their abundance has led to a long-term fundamental change in feedstock selection by the U.S. petrochemical industry, which is the largest consumer of domestic NGLs. In order to capitalize on this cost advantage, U.S. petrochemical companies have maximized their consumption of domestic NGLs. Many of these companies are investing billions of dollars to construct world-scale ethylene plants on the Gulf Coast that are designed to consume NGLs (particularly ethane) as feedstock. U.S. ethylene production capacity is expected to increase by over 40% between 2016 and 2020.

Below is a list of ethylene plants that either have been recently completed or are under construction and expected to begin operations over the next few years based on publicly available information.

Company	**Ethylene Production Capacity**	**Potential Ethane Consumption**	**Estimated Completion Date**
	(Billion lbs/yr)	(MBPD)	
Occidental Chemical/Mexichem	1.2	40	Operational
Dow Chemical	3.3	90	Operational
Chevron Phillips Chemical	3.3	90	1Q 2018
ExxonMobil Chemical	3.3	90	1Q 2018
Indorama	1.1	30	2018
Shintech	1.1	30	2018
Sasol	3.3	90	2018
Formosa Plastics	3.5	95	2019
Axiall/Lotte	2.2	60	2019
Total Petrochemicals & Refining	2.2	60	Early 2020s
Shell	3.5	95	Early 2020s
Total	28.0	770	

Additionally, several other petrochemical companies have announced large scale expansions and/or conversions at existing facilities that will use ethane as feedstock. Almost all of these ethylene plants as well as the major expansions are in close proximity to our existing or planned assets, including our recently completed Aegis Ethane Pipeline.

Based on industry publications, U.S. production of ethylene in 2015 and 2016 averaged 155 million pounds per day. In 2017, U.S. ethylene production averaged 160 million pounds per day despite devastating disruption from Hurricane Harvey, which caused the industry operating rate in September to dip below 70%. Ethane is the most widely used feedstock by the U.S. petrochemical industry in the production of ethylene; ethane consumption by domestic petrochemical companies has, at times, been in excess of 1.2 MMBPD. We believe the U.S. ethylene industry could consume approximately 200 MBPD of additional ethane feedstocks over the next few years through modifications, debottlenecking and expansions at existing facilities. In addition, we believe that publicly announced new petrochemical plant projects, including those noted in the preceding table, could consume well over 700 MBPD of additional ethane feedstocks when completed. However, until these new ethylene plants are completed, ethane production capacity continues to exceed demand, resulting in significant volumes of ethane not being extracted from the natural gas stream by producers and natural gas processors in an effort to balance ethane supply with demand.

In response to growing international demand for U.S. ethane, we placed into service our Morgan's Point Ethane Export Terminal in September 2016. Abundant U.S. ethane from shale plays offers the global petrochemical industry a low-cost feedstock option and supply diversification from a stable producer. The Morgan's Point Ethane Export Terminal, located on the Houston Ship Channel, is the largest of its kind in the world, has an aggregate loading rate (nameplate capacity) of approximately 10,000 barrels per hour of fully refrigerated ethane, and is integrated with our Mont Belvieu NGL fractionation and storage complex.

U.S. exports of LPG continue to increase as a result of ample domestic production, increased export capacity and competitive, transparent pricing when compared to international markets. Overall, U.S. propane waterborne exports increased from approximately 423 MBPD in 2014 to approximately 875 MBPD in 2016 and 989 MBPD in 2017. Markets in Northwest Europe, Central and South America were traditionally the main destination for U.S. LPG exports. However, starting in 2016 a shift towards Asia was underway such that in 2017 exports to Asia have taken the center stage as countries like China and India experience solid and consistent demand growth. For example, Enterprise's exports of LPG to Asia accounted for 14% of that region's total imports in 2016, but in 2017 that figure jumped to 43%. We believe that various factors have favored this rapid tilt towards Asia: (i) continued economic expansion in emerging Asian markets; (ii) the widening of the Panama Canal, which was completed in 2016; and (iii) favorable domestic policies in countries like India and Indonesia where the governments are subsidizing the switch to LPG for domestic use as a means for reducing pollution and protecting against deforestation. In anticipation of the aforementioned growth in LPG exports, we completed the final phase of the expansion of our LPG export terminal located on the Houston Ship Channel at EHT in December 2015. This expansion increased our loading rate for LPG at the terminal to approximately 27,500 barrels per hour (nameplate capacity).

We believe that the U.S. has plentiful supplies of natural gas at very competitive prices. Associated natural gas production from crude oil supply basins tends to be the lowest in cost followed by rich gas plays. However, with enough demand pull, supply basins with dry natural gas, such as the Haynesville/Bossier, Barnett, Fayetteville, Piceance and Jonah/Pinedale, could experience an increase in drilling activity due to their low development costs. The Haynesville resource basin is an excellent example of a dry gas production area that we believe could experience a substantial increase in drilling activity since it is ideally located to serve future demand from LNG exports and industrial customers on the U.S. Gulf Coast. We believe that natural gas prices will tend to stay around $3.00 per MMBtu as there is enough supply to satisfy future demand, both domestic and exports (piped gas to Mexico and waterborne LNG).

Summary

While this period of very low prices has been very difficult for producers, the lower energy prices have led to an increase in energy consumption by consumers, particularly for motor fuels, and by energy intensive industries (e.g., steel manufacturing and petrochemicals) as lower energy and feedstock costs reduce operating costs for their businesses making them more globally competitive. We believe that the ongoing production freeze by OPEC and Russia coupled with an increase in demand for crude oil, natural gas and NGLs from these types of industries, will continue to balance crude oil supply and demand fundamentals and further reduce the overhang of global inventories in 2018. Regardless of such market dynamics, almost all of the major assets we have under construction or have recently completed, whether supply or demand oriented, are supported by long-term fee-based commitments from producers, shippers and/or end-use customers. We also believe that as a result of the price downturn which has slowed and/or caused many higher-risk, long-lead time upstream projects to be cancelled, U.S. unconventional resources have gained substantial long-term significance worldwide and that the U.S. is going to continue to grow in significance as a supplier of hydrocarbons to other nations, particularly in Latin America, Europe and Asia.

Liquidity Outlook

Debt and equity capital markets for the energy sector remained turbulent throughout 2017 as continued volatility and weakness in commodity prices created market uncertainty. This has generally impacted both our cost of capital and access to debt and equity capital markets.

While there were challenges in the capital markets during 2017, we were able to access both the debt and equity capital markets to support our growth and balance sheet objectives at acceptable costs. At December 31, 2017, we had $3.75 billion of consolidated liquidity, which was comprised of $3.74 billion of available borrowing capacity under EPO's revolving credit facilities and $5.1 million of unrestricted cash on hand. Based on current market conditions (as of the filing date of this annual report), we believe we will have sufficient liquidity, cash flow from operations, and access to capital markets and bank capital to fund our capital expenditures and working capital needs for the reasonably foreseeable future.

In February 2018, we issued $2.7 billion aggregate principal amount of senior notes and junior subordinated notes and used the net proceeds therefrom for the temporary repayment of amounts outstanding under our commercial paper program and for the expected redemption of our Junior Subordinated Notes B. For information regarding these debt offerings, see "Significant Recent Developments" within this Item 7.

We have two series of senior notes maturing in April and May of 2018 that have a combined principal amount of $1.1 billion. We expect to refinance these senior notes at or near their maturity. After that, our next maturing series of senior notes are due in January and October of 2019 in the aggregate principal amount of $1.5 billion.

The U.S. government is expected to continue to run substantial annual budget deficits in the coming years that will require a corresponding issuance of debt by the U.S. Treasury. The interest rate on U.S. Treasury debt has a direct impact on the cost of our debt. At this time, we are uncertain what impact the expected large issuances of U.S. Treasury debt and the prevailing economic and capital market conditions during these future periods will have on the cost and availability of capital. We continue to monitor and evaluate the condition of the capital markets and our interest rate risk with respect to funding our capital spending program and refinancing upcoming maturities. For information regarding our interest rate hedging activities, see Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Results of Operations

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

	For the Year Ended December 31, 2017	2016	2015
Revenues	$ 29,241.5	$ 23,022.3	$ 27,027.9
Costs and expenses:			
Operating costs and expenses:			
Cost of sales	21,487.0	15,710.9	19,612.9
Other operating costs and expenses	2,500.1	2,425.6	2,449.4
Depreciation, amortization and accretion expenses	1,531.3	1,456.7	1,428.2
Net losses (gains) attributable to asset sales	(10.7)	(2.5)	15.6
Asset impairment and related charges	49.8	52.8	162.6
Total operating costs and expenses	25,557.5	19,643.5	23,668.7
General and administrative costs	181.1	160.1	192.6
Total costs and expenses	25,738.6	19,803.6	23,861.3
Equity in income of unconsolidated affiliates	426.0	362.0	373.6
Operating income	3,928.9	3,580.7	3,540.2
Interest expense	(984.6)	(982.6)	(961.8)
Change in fair market value of Liquidity Option Agreement	(64.3)	(24.5)	(25.4)
Other, net	1.3	2.8	2.9
Benefit from (provision for) income taxes	(25.7)	(23.4)	2.5
Net income	2,855.6	2,553.0	2,558.4
Net income attributable to noncontrolling interests	(56.3)	(39.9)	(37.2)
Net income attributable to limited partners	$ 2,799.3	$ 2,513.1	$ 2,521.2

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

	For the Year Ended December 31, 2017	2016	2015
NGL Pipelines & Services:			
Sales of NGLs and related products	$ 10,521.3	$ 8,380.5	$ 8,044.8
Midstream services	1,946.7	1,862.0	1,743.2
Total	12,468.0	10,242.5	9,788.0
Crude Oil Pipelines & Services:			
Sales of crude oil	7,365.2	5,802.5	9,732.9
Midstream services	791.6	712.5	573.0
Total	8,156.8	6,515.0	10,305.9
Natural Gas Pipelines & Services:			
Sales of natural gas	2,238.5	1,591.9	1,722.6
Midstream services	907.1	951.1	1,020.7
Total	3,145.6	2,543.0	2,743.3
Petrochemical & Refined Products Services:			
Sales of petrochemicals and refined products	4,696.3	2,921.9	3,333.5
Midstream services	774.8	799.9	778.4
Total	5,471.1	3,721.8	4,111.9
Offshore Pipelines & Services: (1)			
Sales of crude oil	--	--	3.2
Midstream services	--	--	75.6
Total	--	--	78.8
Total consolidated revenues	$ 29,241.5	$ 23,022.3	$ 27,027.9

(1) In July 2015, we completed the sale of our Offshore Business, which comprised our Offshore Pipelines & Services business segment.

Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base. Our largest non-affiliated customer for 2017 was Vitol Holding B.V. and its affiliates (collectively, "Vitol"), which accounted for 11.2% of our consolidated revenues. Vitol is a global energy and commodity trading company.

The following table presents our consolidated revenues from Vitol by business segment for the year ended December 31, 2017 (dollars in millions):

NGL Pipelines & Services	$ 2,099.1
Crude Oil Pipelines & Services	625.6
Natural Gas Pipelines & Services	51.1
Petrochemical & Refined Products Services	512.5
Total	$ 3,288.3

Selected Energy Commodity Price Data

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

	Natural Gas, $/MMBtu	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	PGP, $/pound	Refinery Grade Propylene, $/pound	WTI Crude Oil, $/barrel	LLS Crude Oil, $/barrel
	(1)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(4)	(4)
2015 Averages	$2.67	$0.18	$0.45	$0.61	$0.61	$1.08	$0.39	$0.26	$48.80	$52.38
2016 by quarter:										
1st Quarter	$2.09	$0.16	$0.38	$0.53	$0.53	$0.76	$0.31	$0.18	$33.45	$35.11
2nd Quarter	$1.95	$0.20	$0.49	$0.62	$0.63	$0.96	$0.33	$0.19	$45.59	$47.35
3rd Quarter	$2.81	$0.19	$0.47	$0.63	$0.67	$0.98	$0.38	$0.24	$44.94	$46.52
4th Quarter	$2.98	$0.24	$0.58	$0.83	$0.90	$1.08	$0.36	$0.24	$49.29	$50.53
2016 Averages	$2.46	$0.20	$0.48	$0.65	$0.68	$0.94	$0.34	$0.21	$43.32	$44.88
2017 by quarter:										
1st Quarter	$3.32	$0.23	$0.71	$0.98	$0.94	$1.10	$0.47	$0.32	$51.91	$53.52
2nd Quarter	$3.19	$0.25	$0.63	$0.76	$0.75	$1.07	$0.41	$0.28	$48.28	$50.31
3rd Quarter	$2.99	$0.26	$0.77	$0.91	$0.92	$1.10	$0.42	$0.28	$48.20	$51.62
4th Quarter	$2.93	$0.25	$0.96	$1.04	$1.04	$1.32	$0.49	$0.35	$55.40	$61.07
2017 Averages	$3.11	$0.25	$0.77	$0.92	$0.91	$1.15	$0.45	$0.31	$50.95	$54.13

(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) PGP prices represent average contract pricing for such product as reported by IHS Chemical, a division of IHS Inc. ("IHS Chemical"). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by IHS Chemical.
(4) Crude oil prices are based on commercial index prices for WTI as measured on the New York Mercantile Exchange ("NYMEX") and for Louisiana Light Sweet ("LLS") as reported by Platts.

Fluctuations in our consolidated revenues and cost of sales amounts are explained in large part by changes in energy commodity prices. Energy commodity prices fluctuate for a variety of reasons, including supply and demand imbalances and geopolitical tensions. The weighted-average indicative market price for NGLs was $0.69 per gallon in 2017 versus $0.50 per gallon in 2016 and $0.49 per gallon in 2015.

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 relationship 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 Consolidated Financial Statements included under Part II, Item 8 of this annual 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.

Comparison of 2017 with 2016

Revenues
Total revenues for 2017 increased $6.22 billion when compared to total revenues for 2016. Revenues from the marketing of crude oil, natural gas, petrochemicals, refined products and octane additives increased $3.98 billion year-to-year primarily due to higher sales prices, which accounted for a $2.75 billion increase, and higher sales volumes, which accounted for an additional $1.23 billion increase. Revenues from the marketing of NGLs increased $2.14 billion year-to-year primarily due to higher sales prices, which accounted for a $3.19 billion increase, partially offset by a $1.05 billion decrease due to lower sales volumes.

Revenues from midstream services increased a net $94.7 million year-to-year primarily due to the ongoing expansion of our operations. Revenues increased $54.6 million year-to-year from our Morgan's Point Ethane Export Terminal that was placed into service in September 2016. Revenues increased $48.7 million year-to-year primarily due to higher deficiency fees on our South Texas crude pipelines. In addition, we received $19.1 million of business interruption insurance proceeds related to the June 2016 fire and associated downtime at our Pascagoula facility. These revenue increases were partially offset by a $27.7 million year-to-year decrease in revenues primarily due to lower firm capacity reservation revenues on the Haynesville Extension pipeline and lower volumes and lower average gathering fees on our Jonah Gathering System.

Operating costs and expenses
Total operating costs and expenses for 2017 increased $5.91 billion when compared to total operating costs and expenses for 2016. The cost of sales associated with our marketing of crude oil, natural gas, petrochemicals, refined products and octane additives increased $3.59 billion year-to-year primarily due to higher purchase prices, which accounted for a $2.52 billion increase, and higher sales volumes, which accounted for an additional $1.06 billion increase. The cost of sales associated with our marketing of NGLs increased a net $2.19 billion year-to-year primarily due to higher purchase prices, which accounted for a $3.06 billion increase, partially offset by an $873.9 million decrease due to lower sales volumes.

Other operating costs and expenses for 2017 increased a net $74.5 million when compared to 2016. Other operating costs and expenses increased primarily due to higher employee compensation, power-related costs, ad valorem tax and maintenance expense, partially offset by $17.4 million of proceeds received in connection with a legal settlement involving our Acadian Gas System in the second quarter of 2017.

Depreciation, amortization and accretion expense in operating costs and expenses for 2017 increased a net $74.6 million when compared to 2016 primarily due to assets we constructed and placed into service since 2016.

Operating costs and expenses also include $49.8 million and $52.8 million of non-cash asset impairment and related charges for the years ended December 31, 2017 and 2016, respectively. See Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding our nonrecurring fair value measurements.

General and administrative costs
General and administrative costs for 2017 increased $21.0 million when compared to 2016 primarily due to higher legal, regulatory and employee compensation costs. General and administrative costs for 2016 include $0.7 million of non-cash asset impairment charges.

Equity in income of unconsolidated affiliates
Equity income from our unconsolidated affiliates for 2017 increased a net $64.0 million when compared to 2016 primarily due to an increase in earnings from our investments in crude oil pipelines joint ventures.

Operating income
Operating income for 2017 increased $348.2 million when compared to 2016 due to the previously described year-to-year changes in revenues, operating costs and expenses, general and administrative costs and equity in income of unconsolidated affiliates.

Interest expense
Interest expense for 2017 increased $2.0 million when compared to 2016. The following table presents the components of our consolidated interest expense for the years indicated (dollars in millions):

	For the Year Ended December 31,	
	2017	**2016**
Interest charged on debt principal outstanding	$ 1,110.4	$ 1,088.9
Impact of interest rate hedging program, including related amortization	38.2	30.5
Interest cost capitalized in connection with construction projects (1)	(192.1)	(168.2)
Other (2)	28.1	31.4
Total	$ 984.6	$ 982.6

(1) We capitalize interest costs incurred on funds used to construct property, plant and equipment while the asset is in its construction phase. Capitalized interest amounts become part of the historical cost of an asset and are charged to earnings (as a component of depreciation expense) on a straight line basis over the estimated useful life of the asset once the asset enters its intended service. When capitalized interest is recorded, it reduces interest expense from what it would be otherwise. Capitalized interest amounts fluctuate based on the timing of when projects are placed into service, our capital spending levels and the interest rates charged on borrowings.
(2) Primarily reflects facility commitment fees charged in connection with our revolving credit facilities and amortization of debt issuance costs.

Interest charged on debt principal outstanding, which is the primary driver of interest expense, increased a net $21.5 million year-to-year primarily due to increased debt principal amounts outstanding during 2017, which accounted for a $31.6 million increase, partially offset by the effect of lower overall interest rates in 2017, which accounted for a $10.1 million decrease. Our weighted-average debt principal balance for 2017 was $24.13 billion compared to $23.41 billion for 2016. In general, our debt principal balances have increased over time due to the partial debt financing of our capital spending program. For a discussion of our consolidated debt obligations and capital spending program, see "Liquidity and Capital Resources" and "Capital Spending" within this Part II, Item 7 of this annual report.

Change in fair market value of Liquidity Option Agreement
We recognized an increase of $39.8 million of aggregate non-cash expense attributable to accretion and changes in management estimates regarding inputs to the valuation model for the Liquidity Option Agreement. The unfavorable adjustment was primarily due to the effects of the recent federal tax reform measures known as the Tax Cuts and Jobs Act of 2017 (i.e., limitation of interest expense deductibility, partially offset by a lower federal tax rate). For information regarding the Liquidity Option Agreement, see Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Income taxes
Income taxes primarily reflects our state tax obligations under the Revised Texas Franchise Tax ("Texas Margin Tax"). Our provision for income taxes for 2017 increased $2.3 million when compared to 2016.

Comparison of 2016 with 2015

Revenues
Total revenues for 2016 decreased $4.01 billion when compared to total revenues for 2015. Revenues from the marketing of crude oil decreased $3.93 billion year-to-year due to lower sales volumes and prices, which accounted for a $2.77 billion decrease and a $1.16 billion decrease, respectively. Revenues from the marketing of natural gas, petrochemicals, refined products and octane additives decreased a net $513.8 million year-to-year primarily due to lower sales prices, which accounted for a $760.0 million decrease, partially offset by a $246.2 million increase due to higher sales volumes. Revenues from the marketing of NGLs increased a net $335.7 million year-to-year primarily due to higher sales volumes, which accounted for a $956.2 million increase, partially offset by a $620.5 million decrease due to lower sales prices.

Revenues from midstream services increased a net $134.6 million year-to-year primarily due to the ongoing expansion of our operations. Revenues increased $144.5 million year-to-year from the assets we acquired in the EFS Midstream acquisition in July 2015. Revenues from midstream services decreased $76.0 million year-to-year due to the sale of our Offshore Business in July 2015. The remaining $66.1 million year-to-year increase in revenues from midstream services is primarily due to contractual increases in committed volumes on pipeline assets, such as ATEX and the Aegis Ethane Pipeline ("Aegis"), and the expansion of storage capacity at our terminal assets on the Gulf Coast.

Operating costs and expenses
Total operating costs and expenses for 2016 decreased $4.03 billion when compared to total operating costs and expenses for 2015. The cost of sales associated with our marketing of crude oil decreased $3.69 billion year-to-year due to lower sales volumes and prices, which accounted for a $2.53 billion decrease and a $1.16 billion decrease, respectively. The cost of sales associated with our marketing of natural gas, petrochemicals, refined products and octane additives decreased a net $416.1 million year-to-year primarily due to lower purchase prices, which accounted for a $666.1 million decrease, partially offset by a $250.0 million increase due to higher sales volumes. The cost of sales associated with our marketing of NGLs increased a net $206.5 million year-to-year primarily due to higher sales volumes, which accounted for a $754.2 million increase, partially offset by lower purchase prices, which accounted for a $547.7 million decrease.

Other operating costs and expenses decreased a net $23.8 million year-to-year primarily due to lower maintenance expenses during 2016 when compared to 2015.

Depreciation, amortization and accretion expense in operating costs and expenses for 2016 increased a net $28.5 million when compared to 2015. A $112.8 million year-to-year increase primarily due to assets we constructed and placed into service or acquired during 2016 or the later part of 2015 was partially offset by an $84.3 million decrease attributable to the sale of our Offshore Business in July 2015.

Operating costs and expenses also include $52.8 million and $162.6 million of non-cash asset impairment and related charges for the years ended December 31, 2016 and 2015, respectively. Non-cash asset impairment charges for 2016 primarily relate to the planned abandonment of plant and pipeline assets in Texas and New Mexico. Related charges for 2016 include a $7.1 million non-cash write-off for assets damaged in a fire at our Pascagoula, Mississippi natural gas processing facility in June 2016. In 2015, we recorded a $54.8 million asset impairment charge in connection with our sale of the Offshore Business. The remainder of our non-cash asset impairment charges for 2015 primarily relate to natural gas processing assets in southern Louisiana, certain marine vessels and the abandonment of certain crude oil and natural gas pipeline assets in Texas.

General and administrative costs
General and administrative costs for 2016 decreased $32.5 million when compared to 2015 primarily due to lower costs for employee compensation and professional services. General and administrative costs for 2016 include $0.7 million of non-cash asset impairment charges.

Equity in income of unconsolidated affiliates
Equity income from our unconsolidated affiliates for 2016 decreased a net $11.6 million when compared to 2015. Results for 2015 reflect $46.6 million of equity earnings attributable to the Offshore Business sold in July 2015. This year-to-year decrease was partially offset by a net $30.5 million increase in earnings from our investments in crude oil pipelines, which benefited from the settlement of a rate case by Seaway during 2016.

Operating income
Operating income for 2016 increased $40.5 million when compared to 2015 due to the previously described year-to-year changes in revenues, operating costs and expenses, general and administrative costs and equity in income of unconsolidated affiliates.

Interest expense

Interest expense for 2016 increased $20.8 million when compared to 2015. The following table presents the components of our consolidated interest expense for the years indicated (dollars in millions):

	For the Year Ended December 31, 2016	For the Year Ended December 31, 2015
Interest charged on debt principal outstanding	$ 1,088.9	$ 1,063.4
Impact of interest rate hedging program, including related amortization	30.5	15.4
Interest cost capitalized in connection with construction projects	(168.2)	(149.1)
Other	31.4	32.1
Total	$ 982.6	$ 961.8

Interest charged on debt principal outstanding, which is the primary driver of interest expense, increased a net $25.5 million year-to-year primarily due to increased debt principal amounts outstanding during 2016, which accounted for a $54.8 million increase, partially offset by the effect of lower overall interest rates in 2016, which accounted for a $29.3 million decrease. Our weighted-average debt principal balance for 2016 was $23.41 billion compared to $22.24 billion for 2015.

Change in fair market value of Liquidity Option Agreement

We recognized a decrease of $0.9 million of aggregate non-cash expense attributable to accretion and changes in management estimates regarding inputs to the valuation model for the Liquidity Option Agreement.

Income taxes

Income taxes primarily reflects our state tax obligations under the Texas Margin Tax. Our provision for income taxes for 2016 increased $25.9 million when compared to 2015 primarily due to an increase in accruals for the Texas Margin Tax. In June 2015, the State of Texas lowered the tax rate under the Texas Margin Tax, which resulted in an income tax benefit for us in 2015.

Business Segment Highlights

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 Year Ended December 31, 2017	2016	2015
Gross operating margin by segment:			
NGL Pipelines & Services	$ 3,258.3	$ 2,990.6	$ 2,771.6
Crude Oil Pipelines & Services	987.2	854.6	961.9
Natural Gas Pipelines & Services	714.5	734.9	782.6
Petrochemical & Refined Products Services	714.6	650.6	718.5
Offshore Pipelines & Services	--	--	97.5
Total segment gross operating margin (1)	5,674.6	5,230.7	5,332.1
Net adjustment for shipper make-up rights	5.8	17.1	7.1
Total gross operating margin (non-GAAP)	$ 5,680.4	$ 5,247.8	$ 5,339.2

(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 under Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual 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.

Segment gross operating margin 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 7. The following table presents a reconciliation of operating income to total gross operating margin for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2017	**2016**	**2015**
Operating income (GAAP)	$ 3,928.9	$ 3,580.7	$ 3,540.2
Adjustments to reconcile operating income to total gross operating margin:			
Add depreciation, amortization and accretion expense	1,531.3	1,456.7	1,428.2
Add asset impairment and related charges in operating costs and expenses	49.8	52.8	162.6
Add net losses or subtract net gains attributable to asset sales	(10.7)	(2.5)	15.6
Add general and administrative costs	181.1	160.1	192.6
Total gross operating margin (non-GAAP)	$ 5,680.4	$ 5,247.8	$ 5,339.2

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

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

Estimated Impact of Hurricane Harvey on Results for 2017

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

We estimate that Hurricane Harvey reduced our gross operating margin for the third and fourth quarters of 2017 by approximately $35 million and $11 million, respectively. Of this amount, approximately $30 million represents the combined net impact of lower-than-anticipated volumes and lost business opportunities. The remaining $16 million represents expenses we incurred in connection with hurricane-related repair and recovery costs.

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

Impact on total gross operating margin by segment:		
Petrochemical & Refined Products Services	$	(30.9)
NGL Pipelines & Services		(8.1)
Crude Oil Pipelines & Services		(6.0)
Natural Gas Pipelines & Services		(1.0)
Total estimated impact due to the effects of Hurricane Harvey	$	(46.0)

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

NGL Pipelines & Services

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

	For the Year Ended December 31,		
	2017	2016	2015
Segment gross operating margin:			
Natural gas processing and related NGL marketing activities	$ 911.2	$ 846.6	$ 895.0
NGL pipelines, storage and terminals	1,821.0	1,625.4	1,380.9
NGL fractionation	526.1	518.6	495.7
Total	$ 3,258.3	$ 2,990.6	$ 2,771.6
Selected volumetric data:			
NGL pipeline transportation volumes (MBPD)	3,168	2,965	2,700
NGL marine terminal volumes (MBPD)	516	436	302
NGL fractionation volumes (MBPD)	831	828	826
Equity NGL production (MBPD) (1)	158	141	133
Fee-based natural gas processing (MMcf/d) (2)	4,572	4,736	4,905

(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 natural gas processing plants.

Natural gas processing and related NGL marketing activities

Comparison of 2017 with 2016. Gross operating margin from natural gas processing and related NGL marketing activities for 2017 increased a net $64.6 million when compared to 2016.

Gross operating margin from our natural gas processing plants in Louisiana and Mississippi increased a combined $54.1 million year-to-year primarily due to lower operating expenses, which accounted for $19.4 million of the increase, and the receipt of $19.1 million of business interruption insurance proceeds in connection with the fire and resulting downtime at our Pascagoula facility in June 2016. The facility was repaired and placed back into commercial service in December 2016. Gross operating margin also increased $9.8 million primarily due to higher average processing margins. Fee-based processing volumes for our Louisiana and Mississippi plants increased a combined 138 MMcf/d year-to-year.

Gross operating margin from our Meeker, Pioneer and Chaco natural gas processing plants increased a net $31.5 million year-to-year primarily due to higher average processing margins (including the impact of hedging activities), which accounted for $41.9 million of the increase, partially offset by lower average processing fees, which accounted for a $7.3 million decrease. On a combined basis for these three plants, fee-based natural gas processing volumes and equity NGL production decreased 61 MMcf/d and increased 16 MBPD, respectively, year-to-year.

Gross operating margin from our NGL marketing activities decreased a net $10.4 million year-to-year primarily due to lower average sales margins, which accounted for a $37.9 million decrease, partially offset by higher sales volumes, which accounted for a $20.1 million increase, and lower operating costs, which accounted for an additional $7.4 million increase. Results from NGL marketing's activities decreased $11.4 million year-to-year due to non-cash mark-to-market activity.

Gross operating margin from our natural gas processing plants in South Texas decreased a net $9.9 million year-to-year primarily due to lower fee-based processing volumes, which accounted for a $17.6 million decrease, and higher operating costs of $7.3 million, partially offset by higher average processing margins, which accounted for an $18.0 million increase. Lower producer drilling activity in South Texas contributed to a 352 MMcf/d decrease in fee-based natural gas processing volumes for these plants.

Gross operating margin from our South Eddy natural gas processing plant increased $3.9 million year-to-year. Fee-based natural gas processing volumes and equity NGL production for this plant increased 96 MMcf/d and 3 MBPD, respectively, year-to-year. As previously noted, the South Eddy plant commenced operations in May 2016.

Comparison of 2016 with 2015. Gross operating margin from natural gas processing and related NGL marketing activities for 2016 decreased $48.4 million when compared to 2015.

Collectively, gross operating margin from our Meeker, Pioneer and Chaco plants decreased $53.8 million year-to-year primarily due to lower processing margins, including the impact of our related hedging activities. Gross operating margin from our South Texas plants decreased $49.8 million year-to-year attributable to lower average processing fees and margins, which accounted for a combined $38.1 million decrease, and lower fee-based processing volumes of 227 MMcf/d, which accounted for a $15.8 million decrease. Gross operating margin from our natural gas processing plants in Louisiana and Mississippi decreased a combined $21.6 million year-to-year primarily due to lower processing margins, which accounted for a $6.4 million decrease (including the impact of related hedging activities), and higher operating expenses. Operating expenses at these plants increased $12.1 million year-to-year, which includes $10.4 million of costs attributable to a fire that occurred at our Pascagoula facility in June 2016.

Gross operating margin from our NGL marketing activities increased a net $74.6 million year-to-year primarily due to higher sales volumes, which accounted for a $261.3 million increase, partially offset by a $186.7 million decrease due to lower sales margins. Results from NGL marketing's export-oriented strategies increased $119.2 million year-to-year, which was partially offset by a $44.6 million net decrease in gross operating margin from NGL marketing's other strategies.

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

Comparison of 2017 with 2016. Gross operating margin from NGL pipelines, storage and terminal assets for 2017 increased a net $195.6 million when compared to 2016.

Gross operating margin from ATEX increased $57.2 million year-to-year primarily due to contractual increases in committed shipper volumes and interruptible shipper volumes. Gross operating margin from our equity investments in the Texas Express Gathering System and the Texas Express Pipeline increased a combined $18.3 million year-to-year primarily due to contractual increases in committed shipper volumes. On a combined basis, NGL transportation volumes for these pipeline systems increased 21 MBPD year-to-year (net to our interest).

Gross operating margin from our Morgan's Point Ethane Export Terminal and Houston Ship Channel Pipeline System increased a combined $52.9 million year-to-year primarily due to higher volumes. Ethane loading volumes at our Morgan's Point Ethane Export Terminal increased 75 MBPD year-to-year. In addition, transportation volumes on our Houston Ship Channel Pipeline System increased 105 MBPD year-to-year primarily due to shipments of ethane from Mont Belvieu to the Morgan's Point terminal.

Gross operating margin from our storage complex in Mont Belvieu for NGLs and related products increased $50.7 million year-to-year primarily due to higher average fees in 2017.

Gross operating margin from our Seminole, Chaparral and affiliated pipelines increased a combined net $23.1 million year-to-year primarily due to higher average transportation fees, which accounted for a $15.9 million increase, and higher transportation volumes, which accounted for an additional $14.8 million increase, partially offset by higher operating costs of $6.6 million. On a combined basis, NGL transportation volumes on these pipelines increased 33 MBPD primarily due to increased production from natural gas processing plants located in the Permian Basin and Rocky Mountains.

Gross operating margin from our Dixie Pipeline and related terminals increased a $9.9 million year-to-year primarily due to higher transportation volumes, which increased 19 MBPD year-to-year.

Gross operating margin from our Tri-States NGL Pipeline increased $8.7 million year-to-year primarily due to a 10 MBPD (net to our interest) increase in transportation volumes.

Gross operating margin from our South Texas NGL Pipeline System decreased a net $25.6 million year-to-year primarily due to lower average transportation fees, which accounted for a $13.7 million decrease, lower transportation volumes, which accounted for a $7.0 million of the decrease, and higher maintenance costs, which accounted for an additional $4.1 million decrease. Transportation volumes for the South Texas NGL Pipeline System decreased 21 MBPD year-to-year.

Comparison of 2016 with 2015. Gross operating margin from NGL pipelines, storage and terminal assets for 2016 increased $244.5 million when compared to 2015.

Gross operating margin from ATEX increased $77.2 million year-to-year primarily due to a 39 MBPD increase in transportation volumes. Gross operating margin from Aegis increased $40.7 million year-to-year primarily due to an 84 MBPD increase in transportation volumes. Contracted volume commitments continue to ramp higher through 2018 for ATEX and 2019 for Aegis. The third and final segment of Aegis was completed in December 2015.

Gross operating margin from EHT and the Houston Ship Channel Pipeline System increased $99.5 million year-to-year, primarily due to higher marine terminal and pipeline transportation volumes of 122 MBPD and 113 MBPD, respectively. Gross operating margin from our NGL and related product storage complex in Mont Belvieu, Texas increased $26.1 million year-to-year primarily due to higher fees.

Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related terminals increased $10.7 million year-to-year primarily due to lower operating expenses. Gross operating margin from our South Texas NGL Pipeline System increased $9.3 million year-to-year primarily due to higher transportation fees, which escalated in January 2016.

Gross operating margin from our Morgan's Point Ethane Export Terminal, which was placed into commercial service in September 2016, was a loss of $16.2 million primarily due to commissioning costs.

NGL fractionation

Comparison of 2017 with 2016. Gross operating margin from NGL fractionation for 2017 increased a net $7.5 million when compared to 2016. Gross operating margin from our Mont Belvieu NGL fractionators increased a net $4.1 million primarily due to higher average fractionation fees and blending revenues, which accounted for a $50.8 million increase, partially offset by higher storage, maintenance and power expenses of $47.3 million. NGL fractionation volumes increased 9 MBPD year-to-year, net to our interest.

Comparison of 2016 with 2015. Gross operating margin from NGL fractionation for 2016 increased $22.9 million when compared to 2015 primarily due to higher fractionation revenues at our Mont Belvieu fractionators. Fractionation revenues at Mont Belvieu increased $25.6 million year-to-year primarily due to higher fees, which accounted for a $13.2 million increase, and higher fractionation volumes of 10 MBPD, which accounted for an additional $12.4 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 years indicated (dollars in millions, volumes as noted):

	For the Year Ended December 31,		
	2017	2016	2015
Segment gross operating margin	$ 987.2	$ 854.6	$ 961.9
Selected volumetric data:			
Crude oil pipeline transportation volumes (MBPD)	1,820	1,388	1,474
Crude oil marine terminal volumes (MBPD)	531	495	557

Comparison of 2017 with 2016. Gross operating margin from our Crude Oil Pipelines & Services segment for 2017 increased a net $132.6 million when compared to 2016.

Gross operating margin from our Midland-to-ECHO Pipeline System was $63.3 million for 2017 on transportation volumes of 333 MBPD. This system commenced limited operations in November 2017.

Gross operating margin from our West Texas System and equity investment in the Eagle Ford Crude Oil Pipeline System increased a combined $54.7 million year-to-year primarily due to an 89 MBPD increase in crude oil transportation volumes (net to our interest) from the Permian Basin.

Gross operating margin from our EFS Midstream System increased $31.7 million year-to-year primarily due to increased deficiency fee revenues. Condensate transportation volumes for this system decreased 18 MBPD year-to-year and associated natural gas volumes decreased 101 MMcf/d year-to-year. Gross operating margin for the system decreased $59.7 million year-to-year primarily due to the lower throughput volumes; however, this decrease was more than offset by a $98.1 million year-to-year increase in deficiency fee revenues associated with producer volume commitments.

Gross operating margin from our South Texas Crude Oil Pipeline System increased $25.0 million primarily due to higher firm capacity reservation fees associated with the Midland-to-ECHO Pipeline System, which accounted for a $17.1 million increase, and increased blending revenues, which accounted for an additional $11.5 million increase. Crude oil transportation volumes decreased 9 MBPD year-to-year.

Gross operating margin from crude oil marketing and related activities decreased a net $43.4 million year-to-year primarily due to lower average sales margins, which accounted for a $94.7 million decrease, partially offset by a $35.6 million benefit related to non-cash mark-to-market results, lower pipeline-related costs, which accounted for a $7.8 million increase, and higher earnings from trucking activities, which accounted for an additional $7.5 million increase. Non-cash mark-to-market earnings for this business was a loss of $4.8 million for 2017 versus a loss of $40.4 million for 2016.

Comparison of 2016 with 2015. Gross operating margin from our Crude Oil Pipelines & Services segment for 2016 decreased $107.3 million when compared to 2015.

Gross operating margin from our crude oil marketing and related activities decreased $187.5 million year-to-year primarily due to lower crude oil sales margins, which accounted for a $147.1 million decrease, and $40.4 million of net non-cash mark-to-market losses recognized in 2016 on financial instruments related to blending activities. As a result of lower crude oil prices, regional price spreads have been less than the transportation costs incurred by our marketing business, particularly on its 75 MBPD of firm capacity on the Seaway Pipeline (25 MBPD of this capacity terminated in June 2017).

Gross operating margin from our South Texas Crude Oil Pipeline System decreased $95.0 million year-to-year primarily due to a 74 MBPD decrease in volumes, which accounted for a $66.6 million decrease, and a $32.4 million decrease due to lower average transportation fees. The decrease in crude oil transportation volumes is attributable to reduced producer drilling activity in the Eagle Ford Shale. Gross operating margin from our EFS Midstream system, which we acquired effective July 1, 2015, increased $127.9 million year-to-year due to the timing of the acquisition of these assets. Gross operating margin for this system reflects twelve months of ownership in 2016 versus six months in 2015.

Gross operating margin from crude oil terminaling services at our Beaumont Marine West and ECHO terminals increased a combined $33.9 million year-to-year primarily due to expansion projects.

Gross operating margin from our investment in Seaway for 2016 increased $14.2 million when compared to 2015 primarily due to the settlement of a rate case with the Federal Energy Regulatory Commission ("FERC") in the first quarter of 2016. In February 2016, the FERC issued its decision regarding the various challenges to Seaway's committed and uncommitted rates in FERC Docket No. IS12-226-000. The FERC upheld the committed rates and rejected the claim that the committed rates should be reduced to cost-based levels. The FERC's rulings regarding the uncommitted rates were also largely favorable to Seaway. Seaway submitted a compliance filing in March 2016 calculating revised uncommitted rates consistent with the FERC's order. The compliance filing was not challenged and the FERC accepted the revised rates. On a 100% basis, Seaway recorded a $24.5 million benefit related to settlement of the rate case, with our 50% share of the benefit equating to $12.3 million.

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 years indicated (dollars in millions, volumes as noted):

	For the Year Ended December 31,		
	2017	2016	2015
Segment gross operating margin	$ 714.5	$ 734.9	$ 782.6
Selected volumetric data:			
Natural gas pipeline transportation volumes (BBtus/d)	12,305	11,874	12,321

Comparison of 2017 with 2016. Gross operating margin from our Natural Gas Pipelines & Services segment for 2017 decreased a net $20.4 million when compared to 2016.

Gross operating margin from our Texas Intrastate System decreased $51.4 million year-to-year primarily due to lower firm capacity reservation fees, which accounted for a $30.1 million decrease, lower natural gas transportation volumes, which accounted for an $8.5 million decrease, lower average transportation fees, which accounted for a $7.1 million decrease, and increased operating costs, which accounted for an additional $3.4 million decrease. Natural gas transportation volumes for the Texas Intrastate System decreased 324 BBtus/d year-to-year reflecting reduced drilling activity in the Eagle Ford Shale.

Gross operating margin from our Jonah Gathering System decreased $12.3 million year-to-year primarily due to lower average gathering fees, which accounted for a $6.5 million decrease, a 32 BBtus/d decline in natural gas gathering volumes, which accounted for a $3.4 million decrease, and higher operating costs, which accounted for an additional $3.2 million decrease.

Gross operating margin from our Permian Basin Gathering System increased $10.5 million year-to-year primarily due to a 60 BBtus/d increase in natural gas gathering volumes on the Carlsbad Pipeline, which accounted for a $7.0 million increase, and higher condensate sales revenues, which accounted for an additional $2.4 million increase. Natural gas production in the Permian Basin has increased in connection with a significant rise in crude oil production across West Texas and southeastern New Mexico.

Gross operating margin from the East Texas natural gas pipeline assets we acquired from Azure in April 2017 was $9.0 million on gathering volumes of 220 BBtus/d.

Gross operating margin from our Acadian Gas System increased a net $7.1 million year-to-year primarily due to $17.4 million of proceeds received in a legal settlement in the second quarter of 2017 for lost revenues and damages associated with the Bayou Corne sinkhole incident caused by third parties in 2012, partially offset by lower firm capacity reservation revenues on the Haynesville Extension pipeline, which accounted for a $6.4 million year-to-year decrease, and lower average gathering fees, which accounted for an additional $1.8 million decrease. Gross operating margin from our Haynesville Gathering System increased a net $8.4 million year-to-year primarily due to higher gathering volumes, which accounted for an $11.7 million increase, partially offset by the effects of lower average gathering fees, which accounted for a $2.8 million decrease. Transportation volumes for the Haynesville Extension pipeline, which is a component of the Acadian Gas System, increased 308 BBtus/d and volumes for the Haynesville Gathering System increased 213 BBtus/d.

Gross operating margin from our natural gas marketing activities increased a net $8.8 million year-to-year primarily due to an increase in average sales margins, which accounted for a $7.9 million increase, and higher sales volumes, which accounted for an additional $4.8 million increase, partially offset by non-cash mark-to-market losses, which accounted for a $3.9 million decrease. Non-cash mark-to-market earnings for this business was a loss of $7.9 million in 2017 versus a loss of $4.0 million in 2016.

Comparison of 2016 with 2015. Gross operating margin from our Natural Gas Pipelines & Services segment for 2016 decreased $47.7 million when compared to 2015.

Gross operating margin from our Acadian Gas System decreased $18.8 million year-to-year primarily due to reduced transportation fees. Gross operating margin from our Texas Intrastate System decreased $16.8 million year-to-year primarily due to lower revenues attributable to decreased producer drilling activity in the Eagle Ford Shale and Barnett Shale. Transportation volumes on our Texas Intrastate System decreased 149 BBtus/d year-to-year.

Collectively, gross operating margin for 2016 from our San Juan, Jonah, Piceance Basin and Fairplay Gathering Systems decreased $18.4 million when compared to 2015, the primarily driver of which is a combined 363 BBtus/d decrease in gathering volumes. Gross operating margin from our natural gas marketing activities decreased a net $2.8 million year-to-year primarily due to mark-to-market losses recorded in 2016 on financial instruments related to commodity hedging.

Gross operating margin from our Carlsbad Gathering System in West Texas and New Mexico increased $13.0 million year-to-year primarily due to higher gathering volumes of 97 BBtus/d.

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 years indicated (dollars in millions, volumes as noted):

	For the Year Ended December 31,		
	2017	2016	2015
Segment gross operating margin:			
Propylene production and related activities	$ 222.4	$ 212.1	$ 189.5
Butane isomerization and related operations	72.3	52.0	65.2
Octane enhancement and related plant operations	122.6	42.2	144.3
Refined products pipelines and related activities	280.1	305.6	258.8
Marine transportation and other	17.2	38.7	60.7
Total	$ 714.6	$ 650.6	$ 718.5
Selected volumetric data:			
Propylene production volumes (MBPD)	80	73	71
Butane isomerization volumes (MBPD)	107	108	96
Standalone DIB processing volumes (MBPD)	82	89	79
Octane additive and related plant production volumes (MBPD)	26	22	17
Pipeline transportation volumes, primarily refined products & petrochemicals (MBPD)	792	837	784
Refined products and petrochemical marine terminal volumes (MBPD)	406	389	355

Propylene production and related activities

Comparison of 2017 with 2016. Gross operating margin from propylene production and related marketing activities for 2017 increased a net $10.3 million when compared to 2016.

Gross operating margin from our Mont Belvieu propylene fractionation plants increased a net $33.0 million year-to-year primarily due to higher propylene average sales margins and volumes, which accounted for a $43.5 million increase, and higher average propylene fractionation fees, which accounted for an additional $13.8 million increase, partially offset by an increase in maintenance, storage and other operating costs of $23.9 million. Gross operating margin from the PDH facility decreased $13.3 million year-to-year primarily due to higher commissioning costs. We expect the PDH facility to enter full service during the first quarter of 2018.

Gross operating margin from our Mont Belvieu rail terminal decreased $2.4 million year-to-year primarily due to lower loading volumes of 4 MBPD. Gross operating margin from our propylene export marine terminals decreased a net $1.4 million year-to-year primarily due to lower average loading fees, which accounted for a $7.3 million decrease, partially offset by lower operating costs, which accounted for a $4.3 million increase.

Comparison of 2016 with 2015. Gross operating margin from propylene fractionation and related activities for 2016 increased $22.6 million when compared to 2015. Gross operating margin from our Mont Belvieu propylene fractionation plants increased a net $37.1 million year-to-year. When compared to results for 2015, these plants benefitted in 2016 from $29.6 million of lower operating costs, $16.6 million of higher propylene fractionation and other fee revenues, and a $13.1 million increase in gross operating margin attributable to higher propylene fractionation volumes of 3 MBPD. The year-to-year decrease in operating costs is attributable to major maintenance projects that were completed in 2015. Partially offsetting these benefits was a $22.2 million year-to-year decrease in gross operating margin attributable to lower propylene sales margins.

Pre-commissioning expenses associated with our PDH facility increased $15.5 million during 2016 when compared to 2015.

Butane isomerization and related operations

Comparison of 2017 with 2016. Gross operating margin from butane isomerization and deisobutanizer ("DIB") operations for 2017 increased $20.3 million when compared to 2016. Operating expenses associated with our isomerization facility in Mont Belvieu, Texas decreased $15.5 million year-to-year primarily due to major maintenance activities completed during 2016. By-product sales revenues increased a net $7.2 million year-to-year primarily due to higher average sales prices, which accounted for a $21.7 million increase, offset by lower sales volumes, which accounted for a $14.5 million decrease.

Comparison of 2016 with 2015. Gross operating margin from butane isomerization and DIB operations for 2016 decreased a net $13.2 million when compared to 2015. Operating expenses associated with our isomerization facility in Mont Belvieu, Texas increased $22.4 million year-to-year primarily due to major maintenance activities we completed during 2016. Butane processing revenues increased $7.8 million year-to-year primarily due to higher butane isomerization and standalone DIB processing volumes of 12 MBPD and 10 MBPD, respectively.

Octane enhancement and related plant operations

Comparison of 2017 with 2016. Gross operating margin from our octane enhancement facility and high purity isobutylene ("HPIB") plant for 2017 increased $80.4 million when compared to 2016. Gross operating margin from our octane enhancement facility increased $80.7 million year-to-year primarily due to lower major maintenance costs, which accounted for $42.6 million of the increase, and higher sales volumes, which accounted for an additional $30.5 million increase.

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

Comparison of 2016 with 2015. Gross operating margin from our octane enhancement facility and HPIB plant for 2016 decreased $102.1 million when compared to 2015. This year-to-year decrease in gross operating margin is primarily due to lower sales margins, including the results of our related hedging activities.

Refined products pipelines and related activities

Comparison of 2017 with 2016. Gross operating margin from refined products pipelines and related marketing activities for 2017 decreased a net $25.5 million when compared to 2016.

Gross operating margin from refined products marketing decreased a net $18.3 million year-to-year primarily due to lower average refined products sales margins, which accounted for a $30.0 million decrease, partially offset by a $12.0 million year-to-year increase in non-cash mark-to-market income. Non-cash mark-to-market earnings for this business was a gain of $2.4 million in 2017 versus a loss of $9.6 million in 2016.

Gross operating margin from our Beaumont and Houston Ship Channel refined products marine terminals decreased a combined $14.2 million year-to-year primarily due to higher operating costs.

Gross operating margin from our TE Products Pipeline increased a net $7.3 million year-to-year primarily due to higher average transportation fees, which accounted for a $10.8 million increase, partially offset by lower transportation volumes, which accounted for a $5.8 million decrease. Transportation volumes for the TE Products Pipeline decreased 24 MBPD primarily due to lower refined products and petrochemical product movements during 2017.

Comparison of 2016 with 2015. Gross operating margin from refined products pipelines and related marketing activities for 2016 increased $46.8 million when compared to 2015. Gross operating margin from our Beaumont refined products terminals increased $24.9 million year-to-year primarily due to expansions and higher demand for storage and marine vessel loading services.

Gross operating margin for the TE Products Pipeline and related terminals increased $20.1 million year-to-year primarily due to higher volumes. Interstate refined products pipeline transportation volumes on our TE Products Pipeline increased 10 MBPD year-to-year. Intrastate refined products and petrochemical pipeline transportation volumes on our TE Products Pipeline increased a combined 40 MBPD year-to-year.

Marine transportation and other

Comparison of 2017 with 2016. Gross operating margin from marine transportation and other activities for 2017 decreased $21.5 million when compared to 2016. Gross operating margin attributable to our marine transportation business decreased $18.1 million year-to-year primarily due to lower average fees.

Comparison of 2016 with 2015. Gross operating margin from marine transportation and other activities for 2016 decreased $22.0 million when compared to 2015 primarily due to lower demand for marine transportation services attributable to the lower commodity pricing environment.

Offshore Pipelines & Services

We sold our Offshore Business in July 2015. The following table presents segment gross operating margin and selected volumetric data through the closing date of the sale, July 24, 2015 (dollars in millions, volumes as noted).

Segment gross operating margin	$ 97.5
Selected volumetric data:	
Natural gas transportation volumes (BBtus/d)	587
Crude oil transportation volumes (MBPD)	357
Platform natural gas processing (MMcf/d)	101
Platform crude oil processing (MBPD)	13

Liquidity and Capital Resources

Based on current market conditions (as of the filing date of this annual 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 December 31, 2017, we had $3.75 billion of consolidated liquidity, which was comprised of $3.74 billion of available borrowing capacity under EPO's revolving credit facilities and $5.1 million of unrestricted cash on hand.

In February 2018, we issued $2.7 billion aggregate principal amount of senior notes and junior subordinated notes and used the net proceeds therefrom for the temporary repayment of amounts outstanding under our commercial paper program and for the expected redemption of all $682.7 million aggregate principal amount of our Junior Subordinated Notes B. For information regarding these debt offerings and the related redemption, see "Significant Recent Developments" within this Item 7. We expect to issue additional equity and debt securities to assist us in meeting our future funding and liquidity requirements, including those related to capital spending.

Consolidated Debt

The following table presents scheduled maturities of our consolidated debt obligations outstanding at December 31, 2017 for the years indicated (dollars in millions):

		Scheduled Maturities of Debt					
	Total	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**
Commercial Paper Notes	$ 1,755.7	$ 1,755.7	$ --	$ --	$ --	$ --	$ --
Senior Notes	19,850.0	1,100.0	1,500.0	1,500.0	575.0	650.0	14,525.0
Junior Subordinated Notes	3,174.4	--	--	--	--	--	3,174.4
Total	$ 24,780.1	$ 2,855.7	$ 1,500.0	$ 1,500.0	$ 575.0	$ 650.0	$ 17,699.4

The following information describes significant transactions that affected our consolidated debt obligations during the year ended December 31, 2017:

Issuance of $1.7 Billion of Junior Subordinated Notes in August 2017

In August 2017, EPO issued a combined $1.7 billion in principal amount of junior subordinated notes in two series. The EPO Junior Subordinated Notes D ("Junior Notes D"), which were issued at $700 million principal amount in the aggregate, are redeemable at EPO's option, in whole or in part, on one or more occasions, on or after August 16, 2022 (the non-call 5 notes) at 100% of their principal amount, plus any accrued and unpaid interest. Junior Notes D bear interest at a fixed rate of 4.875% per year through August 15, 2022. Beginning August 16, 2022, Junior Notes D will bear interest at a floating rate based on a three-month LIBOR rate plus 2.986%, reset quarterly. Junior Notes D mature in August 2077.

The EPO Junior Subordinated Notes E ("Junior Notes E"), which were issued at $1.0 billion principal amount in the aggregate, are redeemable at EPO's option, in whole or in part, on one or more occasions, on or after August 16, 2027 (the non-call 10 notes) at 100% of their principal amount, plus any accrued and unpaid interest. Junior Notes E bear interest at a fixed rate of 5.25% per year through August 15, 2027. Beginning August 16, 2027, Junior Notes E will bear interest at a floating rate based on a three-month LIBOR rate plus 3.033%, reset quarterly. Junior Notes E also mature in August 2077.

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

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

364-Day Revolving Credit Agreement

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

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

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

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

Multi-Year Revolving Credit Facility

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

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

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

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

Issuance of Common Units

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

	Number of Common Units Issued	Net Cash Proceeds Received
Year Ended December 31, 2015:		
Common units issued in connection with ATM program	25,520,424	$ 817.4
Common units issued in connection with DRIP and EUPP	12,793,913	371.2
Total	38,314,337	$ 1,188.6
Year Ended December 31, 2016:		
Common units issued in connection with ATM program	87,867,037	$ 2,156.1
Common units issued in connection with DRIP and EUPP	16,316,534	386.7
Total	104,183,571	$ 2,542.8
Year Ended December 31, 2017:		
Common units issued in connection with ATM program	21,807,726	$ 597.0
Common units issued in connection with DRIP and EUPP	19,046,019	476.4
Total	40,853,745	$ 1,073.4

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.

ATM Program

In November 2017, we filed an amended registration statement 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. The registration statement was declared effective by the SEC on November 20, 2017 and replaced our prior registration statement with respect to the ATM program. Following the effectiveness of the new registration statement and after taking into account the aggregate sales price of common units sold under the ATM program through December 31, 2017, we have the capacity to issue additional common units under the ATM program up to an aggregate sales price of $2.54 billion.

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 December 31, 2017, we have the capacity to issue an additional 80,717,140 common units under this plan.

Affiliates of EPCO purchased $100 million of our common units through the DRIP in connection with the distribution paid on February 7, 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 December 31, 2017, we had the capacity to issue an additional 5,760,811 common units under this plan.

Use of Proceeds

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

For additional information regarding our issuance of common units and related registration statements, see Note 9 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Restricted Cash

Restricted cash represents amounts held in segregated bank accounts by our clearing brokers as margin in support of our commodity derivative instruments portfolio and related physical purchases and sales of natural gas, NGLs, crude oil and refined products. Additional cash may be restricted to maintain our commodity derivative instruments portfolio as prices fluctuate or margin requirements change.

At December 31, 2017 and 2016, our restricted cash amounts were $65.2 million and $354.5 million, respectively. The balance of restricted cash decreased since December 31, 2016 primarily due to the settlement of derivative instruments related to contango positions during 2017. For information regarding our derivative instruments and hedging activities, see Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Credit Ratings

As of February 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 years indicated (dollars in millions). For additional information regarding our cash flow amounts, please refer to the Statements of Consolidated Cash Flows included under Part II, Item 8 of this annual report.

	For the Year Ended December 31,		
	2017	**2016**	**2015**
Net cash flows provided by operating activities	$ 4,666.3	$ 4,066.8	$ 4,002.4
Cash used in investing activities	3,286.1	4,005.8	3,425.9
Cash provided by (used in) financing activities	(1,727.5)	321.7	(616.0)

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.

Risks of nonpayment and nonperformance by customers are a major consideration in our businesses, and our credit procedures and policies may not be adequate to sufficiently eliminate customer credit risk. Further, adverse economic conditions in our industry, such as those experienced throughout 2015 and 2016, increase the risk of nonpayment and nonperformance by customers, particularly customers that have sub-investment grade credit ratings or small-scale companies. Such non-performance risk could be associated with long-term contracts with minimum volume commitments or fixed demand charges. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments, net out agreements and guarantees. However, these procedures and policies do not fully eliminate customer credit risk.

Our primary markets are located in the Gulf Coast, Southwest, Rocky Mountain, Northeast and Midwest regions of the U.S. We have a concentration of trade receivable balances due from independent and major integrated oil and gas companies and other pipelines and wholesalers. These concentrations may affect our overall credit risk in that these energy industry customers may be similarly affected by changes in economic, regulatory or other factors.

For a more complete discussion of these and other risk factors pertinent to our business, see Part I, Item 1A of this annual report.

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

Comparison of 2017 with 2016

Operating activities. Net cash flows provided by operating activities for the year ended December 31, 2017 increased $599.5 million when compared to the year ended December 31, 2016. The increase in cash provided by operating activities was primarily due to:

- a $333.2 million increase in cash resulting from higher partnership earnings in the year ended December 31, 2017 compared to the same period in 2016 (after adjusting our $302.6 million year-to-year increase in net income for changes in the non-cash items identified on our Statements of Consolidated Cash Flows);

- a $213.1 million year-to-year increase in cash primarily due to the timing of cash receipts and payments related to operations; and

- a $53.2 million year-to-year increase in cash distributions received on earnings from unconsolidated affiliates primarily due to our investments in crude oil pipeline joint ventures.

For information regarding significant year-to-year changes in our consolidated net income and underlying segment results, see "Results of Operations" within this Part II, Item 7.

Investing activities. Cash used for investing activities for the year ended December 31, 2017 decreased $719.7 million when compared to the same period in 2016 primarily due to:

- an $801.3 million year-to-year decrease in cash used for business combinations, net of cash received. During the year ended December 31, 2017, net cash used for business combinations was $198.7 million, which was primarily related to the Azure acquisition. During the same period in 2016, $1.0 billion was paid for the second and final installment for the acquisition of EFS Midstream; and

- an $88.3 million year-to-year decrease in investments in unconsolidated affiliates primarily due to the completion of construction of certain NGL and crude oil joint venture projects; partially offset by

- a $117.7 million year-to-year increase in capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs (see "Capital Spending" within this Part II, Item 7 for additional information regarding our capital spending program).

Financing activities. Cash used in financing activities for the year ended December 31, 2017 was $1.73 billion compared to cash provided by financing activities of $321.7 million for the year ended December 31, 2016. The $2.05 billion year-to-year change in cash flow from financing activities was primarily due to:

- a $1.47 billion year-to-year decrease in net cash proceeds from the issuance of common units. We issued an aggregate 40,853,745 common units, which generated $1.07 billion of net cash proceeds, in connection with our ATM program, DRIP and EUPP during the year ended December 31, 2017. This compares to an aggregate 104,183,571 common units we issued in connection with these programs and plans during the same period in 2016, which collectively generated $2.54 billion of net cash proceeds;

- a $285.6 million year-to-year decrease in net cash inflows attributable to our consolidated debt obligations. EPO issued $1.7 billion in principal amount of junior subordinated notes and repaid $800.0 million in principal amount of senior notes during the year ended December 31, 2017 compared to the issuance of $1.25 billion and repayment of $750.0 million in principal amount of senior notes during the year ended December 31, 2016. In addition, net repayments under EPO's commercial paper program were $44.2 million during 2017 compared to net issuances of $647.9 million during 2016; and

- a $269.4 million year-to-year increase in cash distributions paid to limited partners during the year ended December 31, 2017 when compared to the same period in 2016. The increase in cash distributions is due to increases in both the number of distribution-bearing common units outstanding and the quarterly cash distribution rates per unit.

Comparison of 2016 with 2015

Operating Activities
Net cash flows provided by operating activities for the year ended December 31, 2016 increased $64.4 million when compared to the year ended December 31, 2015. The increase in cash provided by operating activities was primarily due to a $142.4 million year-to-year increase in cash primarily due to the timing of cash receipts and payments related to operations partially offset by an $81.6 million year-to-year decrease in cash distributions received on earnings from unconsolidated affiliates primarily due to the sale of our Offshore Business in July 2015.

For information regarding significant year-to-year changes in our consolidated net income and underlying segment results, see "Results of Operations" within this Part II, Item 7.

Investing Activities
Cash used in investing activities for the year ended December 31, 2016 increased $579.9 million when compared to the year ended December 31, 2015 primarily due to:

- a $1.56 billion year-to-year decrease in cash proceeds from asset sales primarily due to the sale of our Offshore Business in July 2015, which generated proceeds of $1.53 billion; and

- an $827.5 million year-to-year decrease in capital spending for consolidated property, plant and equipment;

- an $80.3 million year-to-year decrease in aggregate cash used for business combinations and investments in and advances to unconsolidated affiliates; and

- $71.0 million of distributions received in connection with the return of capital from unconsolidated affiliates during 2016.

Financing Activities
Cash provided by financing activities for the year ended December 31, 2016 was $321.7 million compared to cash used in financing activities for the year ended December 31, 2015 of $616.0 million. The $937.7 million year-to-year change in cash flow from financing activities was primarily due to:

- a $1.35 billion year-to-year increase in net cash proceeds from the issuance of common units. We issued an aggregate 104,183,571 common units in connection with our ATM program, DRIP and EUPP during 2016, which generated $2.54 billion of net cash proceeds. This compares to an aggregate 38,314,337 common units we issued in connection with these programs and plans during 2015, which collectively generated $1.19 billion of net cash proceeds; partially offset by

- a $356.8 million year-to-year increase in cash distributions paid to limited partners during 2016 when compared to 2015. The increase in cash distributions is due to increases in both the number of distribution-bearing common units outstanding and the quarterly cash distribution rates per unit; and

- a $72.6 million year-to-year decrease in net borrowings under our consolidated debt agreements. EPO issued $1.25 billion and repaid $750.0 billion in principal amount of senior notes during 2016, compared to the issuance of $2.5 billion and repayment of $1.48 billion in principal amount of senior and junior notes during 2015. Net proceeds from the issuance of short-term notes under EPO's commercial paper program were $647.9 million during 2016 compared to $202.2 million during 2015.

Cash Distributions to Limited Partners

Our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash, after any cash reserves established by Enterprise GP in its sole discretion. Cash reserves include those for the proper conduct of our business including, for example, those for capital expenditures, debt service, working capital, operating expenses, commitments and contingencies and other significant amounts. The retention of cash by the partnership allows us to reinvest in our growth and reduce our future reliance on the equity and debt capital markets.

In January 2018, the Board declared a cash distribution of $0.4250 per common unit with respect to the fourth quarter of 2017. In addition, our management announced plans in October 2017 to recommend to the Board additional quarterly cash distribution increases of $0.0025 per unit with respect to each of the four quarters of 2018. For additional information regarding our expected distribution growth rate, see "Significant Recent Developments" within this Item 7.

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 7.

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

	For the Year Ended December 31,		
	2017	2016	2015
Net income attributable to limited partners (1)	$ 2,799.3	$ 2,513.1	$ 2,521.2
Adjustments to GAAP net income attributable to limited partners to derive non-GAAP distributable cash flow:			
Add depreciation, amortization and accretion expenses	1,644.0	1,552.0	1,516.0
Add non-cash asset impairment and related charges	49.8	53.5	162.6
Add losses or subtract gains attributable to asset sales	(10.7)	(2.5)	15.6
Add cash proceeds from asset sales (2)	40.1	46.5	1,608.6
Add changes in fair value of Liquidity Option Agreement (3)	64.3	24.5	25.4
Add or subtract changes in fair market value of derivative instruments	22.8	45.0	(18.4)
Add cash distributions received from unconsolidated affiliates (4)	483.0	451.5	462.1
Subtract equity in income of unconsolidated affiliates	(426.0)	(362.0)	(373.6)
Subtract sustaining capital expenditures (5)	(243.9)	(252.0)	(272.6)
Add gains from monetization of interest rate derivative instruments accounted for as cash flow hedges (6)	30.6	6.1	--
Add deferred income tax expense or subtract benefit, as applicable	6.1	6.6	(20.6)
Other, net	42.9	20.5	(19.0)
Distributable cash flow	$ 4,502.3	$ 4,102.8	$ 5,607.3
Total cash distributions paid to limited partners with respect to period	$ 3,635.2	$ 3,394.0	$ 3,036.8
Cash distributions per unit declared by Enterprise GP with respect to period (7)	$ 1.6825	$ 1.6100	$ 1.5300
Total distributable cash flow retained by partnership with respect to period (8)	$ 867.1	$ 708.8	$ 2,570.5
Distribution coverage ratio (9)	1.24x	1.21x	1.85x

(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 II, Item 7.
(2) For a discussion of significant changes in cash proceeds from asset sales as presented in the investing activities section of our Statements of Consolidated Cash Flows, see "Cash Flows from Operating, Investing and Financing Activities" within this Part II, Item 7.
(3) For information regarding the Liquidity Option Agreement, see Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.
(4) Reflects both distributions received on earnings from unconsolidated affiliates and those attributable to a return of capital from unconsolidated affiliates. For information regarding our unconsolidated affiliates, see Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.
(5) Sustaining capital expenditures include cash payments and accruals applicable to the period.
(6) For information regarding these gains, see "Interest Rate Hedging Activities" under Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.
(7) See Note 9 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for additional information regarding our quarterly cash distributions declared with respect to the periods presented.
(8) At the sole discretion of Enterprise GP, cash retained by the partnership with respect to each of these years was primarily reinvested in our growth capital spending program, which substantially reduced our reliance on the equity and debt capital markets to fund such major expenditures.
(9) 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 Year Ended December 31,		
	2017	2016	2015
Net cash flows provided by operating activities	$ 4,666.3	$ 4,066.8	$ 4,002.4
Adjustments to reconcile net cash flows provided by operating activities to distributable cash flow:			
Subtract sustaining capital expenditures	(243.9)	(252.0)	(272.6)
Add cash proceeds from asset sales	40.1	46.5	1,608.6
Add gains from monetization of interest rate derivative instruments accounted for as cash flow hedges	30.6	6.1	--
Net effect of changes in operating accounts	(32.2)	180.9	323.3
Other, net	41.4	54.5	(54.4)
Distributable cash flow	$ 4,502.3	$ 4,102.8	$ 5,607.3

Designated Units Issued in Connection with Holdings Merger

In November 2010, we completed our merger with Enterprise GP Holdings L.P. (the "Holdings Merger"). In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular cash distributions it would otherwise receive from us with respect to a certain number of our common units it owns (the "Designated Units"). Distributions paid by us to this privately held affiliate of EPCO during 2015 excluded 35,380,000 Designated Units. The temporary distribution waiver expired in November 2015; therefore, distributions paid to partners during calendar years 2016 and 2017 were on all outstanding common units.

Capital Spending

An important part of our business strategy involves expansion through growth capital projects, business combinations and investments in joint ventures. We believe that we are well positioned to continue to expand our network of assets through the construction of new facilities and to capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountains, Mid-Continent, Northeast and U.S. Gulf Coast regions, including the Niobrara, Barnett, Eagle Ford, Permian, Haynesville, Marcellus and Utica Shale plays. Although our focus in recent years has been on expansion through growth capital projects, management continues to analyze potential business combinations, asset acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions.

We placed approximately $4.5 billion of major growth capital projects into service or commissioning during 2017, including our PDH facility, our Midland-to-ECHO Pipeline System (limited service) and expansions related to our propylene pipeline system and Beaumont refined products terminal. We have approximately $5.5 billion of growth capital projects scheduled to be completed by the end of 2020 including our ninth NGL fractionator in Mont Belvieu, Texas (second quarter of 2018), the completion of joint venture-owned dock infrastructure in Corpus Christi designed to accommodate crude oil volumes (third quarter of 2018), the Shin Oak NGL pipeline (second quarter of 2019), our iBDH facility (fourth quarter of 2019) and the ethylene export terminal (first quarter of 2020).

Based on information currently available, we expect our total capital spending for 2018 to approximate $3.3 billion, which includes approximately $315 million for sustaining capital expenditures. Our forecast of capital spending for 2018 is based on our announced strategic operating and growth plans (through the filing date of this annual 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 Year Ended December 31,		
	2017	2016	2015
Capital spending for property, plant and equipment: (1)			
Growth capital projects (2)	$ 2,868.8	$ 2,722.7	$ 3,540.0
Sustaining capital projects (3)	233.0	261.4	271.6
Total	$ 3,101.8	$ 2,984.1	$ 3,811.6
Business combinations:			
Cash used for business combinations (4)	$ 198.7	$ 1,000.0	$ 1,056.5
Non-cash equity consideration (5)	--	--	1,408.7
Total	$ 198.7	$ 1,000.0	$ 2,465.2
Investments in unconsolidated affiliates	$ 50.5	$ 138.8	$ 162.6

(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 for 2017 primarily represents net cash used for the Azure acquisition in April 2017. Amounts for 2016 and 2015 represent the first and second payments for EFS Midstream. We acquired EFS Midstream in July 2015 for approximately $2.1 billion in cash, which was payable in two installments.
(5) Amount presented for 2015 relates to the acquisition of noncontrolling interests in step two of the Oiltanking acquisition.

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 year ended December 31, 2017 involved projects at our Mont Belvieu complex as well as projects to support crude oil, natural gas and NGL production from the Permian Basin. Fluctuations in spending for sustaining capital projects are explained in large part by the timing and cost of pipeline integrity and similar projects.

Comparison of 2017 with 2016. Growth capital spending for projects to support Permian Basin production increased $909.5 million year-to-year primarily due to increased capital spending for the Midland-to-ECHO Pipeline System, which accounted for $480.2 million of the increase, construction of our Orla I and Orla II plants and related pipelines, which accounted for an additional $422.1 million of the increase, partially offset by decreased capital spending on our South Eddy plant and related pipelines, which accounted for $131.2 million of the decrease. We placed the Midland-to-ECHO Pipeline System into limited commercial service in November 2017. Additionally, we completed construction and placed the South Eddy facility into service in May 2016.

Growth capital spending for our Morgan's Point Ethane Export Terminal and our LPG export expansion project decreased a combined $299.3 million. Our Morgan's Point Ethane Export Terminal, which has an aggregate loading rate (nameplate capacity) of approximately 10,000 barrels per hour of fully refrigerated ethane and is the largest of its kind in the world, was placed into service in September 2016.

Growth capital spending for projects at our Mont Belvieu complex decreased $271.9 million year-to-year, primarily due to decreased capital spending at our PDH facility, which accounted for a $443.8 million decrease, partially offset by increased capital spending on our ninth NGL fractionator, which accounted for a $141.9 million increase, and our iBDH unit, which accounted for a $93.2 million additional increase.

Growth capital spending at our ECHO and Beaumont Marine West Crude Oil terminals decreased a combined $103.7 million year-to-year as new storage tanks and related assets were placed into service at these facilities during 2016.

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

Investments in unconsolidated affiliates decreased $88.3 million year-to-year primarily due to the completion of construction of certain NGL and crude oil joint venture projects.

Comparison of 2016 with 2015. Growth capital spending for LPG export expansion projects at EHT and our ethane export facility decreased a combined $328.9 million year-to-year. We completed two expansion projects during 2015 at our EHT facility that increased our ability to load cargos of fully refrigerated, low-ethane propane to approximately 16.0 MMBbls per month. Likewise, growth capital spending on our ethane header system between Corpus Christi, Texas and the Mississippi River in Louisiana decreased $288.1 million year-to-year. We completed the Aegis Ethane Pipeline (i.e., the largest component of our ethane header system) in December 2015.

Growth capital spending at our ECHO and Beaumont Marine West Crude Oil terminals decreased a combined $146.1 million year-to-year as new storage tanks and related assets were placed into service at these facilities during 2015 and 2016. Growth capital spending for our Rancho II crude oil pipeline, which is a component of our South Texas Crude Oil Pipeline System, and Midland-to-ECHO Pipeline System decreased a net $95.0 million year-to-year. We completed the Rancho II pipeline in September 2015.

Growth capital spending at our Mont Belvieu complex increased $67.1 million year-to-year primarily due to construction of our PDH facility.

We acquired EFS Midstream in July 2015 for approximately $2.1 billion in cash, which was payable in two installments. The initial payment of $1.1 billion was paid at closing in July 2015. The second and final installment of $1.0 billion was paid in July 2016 using a combination of cash on hand and proceeds from the issuance of short-term notes under EPO's commercial paper program. Also, in February 2015, we issued 36,827,517 common units valued at approximately $1.4 billion to complete Step 2 of the Oiltanking acquisition. For information regarding these acquisitions, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8, of this annual report.

Investments in unconsolidated affiliates decreased $23.8 million year-to-year primarily due to the completion of expansion projects on our Eagle Ford Crude Oil Pipeline System during 2015.

Critical Accounting Policies and Estimates

In our financial reporting processes, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses for each reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following sections discuss the use of estimates within our critical accounting policies:

Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively. Examples of such circumstances include (i) changes in laws and regulations that limit the estimated economic life of an asset, (ii) changes in technology that render an asset obsolete, (iii) changes in expected residual values or (iv) significant changes in our forecast of the remaining life for the applicable resource basins, if any.

At December 31, 2017 and 2016, the net carrying value of our property, plant and equipment was $35.62 billion and $33.29 billion, respectively. We recorded $1.3 billion, $1.22 billion and $1.16 billion of depreciation expense for the years ended December 31, 2017, 2016 and 2015, respectively. For additional information regarding our property, plant and equipment, see Note 5 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Measuring Recoverability of Long-Lived Assets and Fair Value of Equity Method Investments

Long-lived assets (including property, plant and equipment and intangible assets with finite useful lives) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, NGLs, crude oil, petrochemicals or refined products. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the asset. Estimates of undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated residual values. If the carrying value of a long-lived asset is not recoverable, an impairment charge would be recorded for the excess of a long-lived asset's carrying value over its estimated fair value, which is derived from an analysis of the asset's estimated future cash flows, the market value of similar assets and replacement cost of the asset less any applicable depreciation or amortization. In addition, fair value estimates also include usage of probabilities for a range of possible outcomes.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible permanent loss in value of the investment (i.e., other than a temporary decline). Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee's industry. When evidence of a loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. We assess the fair value of our equity method investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party sales and discounted estimated cash flow models. Estimates of discounted cash flows are based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment's underlying assets.

A significant change in the assumptions we use to measure recoverability of long-lived assets and the fair value of equity method investments could result in our recording a non-cash impairment charge. Any write-down of the carrying values of such assets would increase operating costs and expenses at that time.

During 2017, 2016 and 2015, we recognized non-cash asset impairment charges related to long-lived assets of $37.8 million, $45.2 million and $162.6 million, respectively, which are a component of costs and expenses. For additional information regarding these impairment charges, see Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Amortization Methods and Estimated Useful Lives of Customer Relationships and Contract-Based Intangible Assets

The specific, identifiable intangible assets of a business depend largely upon the nature of its operations and include items such as customer relationships and contracts. The method used to value such assets depends on a number of factors, including the nature of the asset and the economic returns the asset is expected to generate.

Customer relationship intangible assets represent the estimated economic value assigned to certain relationships acquired in connection with business combinations and asset purchases whereby (i) we acquired information about or access to customers and now have the ability to provide services to them and (ii) the customers now have the ability to make direct contact with us. Customer relationships may arise from contractual arrangements (such as service contracts) and through means other than contracts, such as through regular contact by sales or service representatives. The value we assign to customer relationships is amortized to earnings using methods that closely resemble the pattern in which the economic benefits will be consumed (i.e., the manner in which the intangible asset is expected to contribute directly or indirectly to our cash flows). For example, the amortization periods for certain of our customer relationship intangible assets are limited by the estimated finite economic life of the associated hydrocarbon resource basins. In this context, our estimate of the useful life of each resource basin is predicated on a number of factors, including reserve estimates and the economic viability of production and exploration activities.

Contract-based intangible assets represent specific commercial rights we own arising from discrete contractual agreements, such as the long-term rights we possess under the Shell natural gas processing agreement and the Jonah natural gas gathering contracts. A contract-based intangible asset with a finite life is amortized over its estimated economic life, which is the period over which the asset is expected to contribute directly or indirectly to our cash flows. Our estimates of the economic life of contract-based intangible assets are based on a number of factors, including (i) the expected useful life of the related tangible assets (e.g., a fractionation facility, pipeline or other asset), (ii) any legal or regulatory developments that would impact such contractual rights and (iii) any contractual provisions that enable us to renew or extend such arrangements.

If our assumptions regarding the estimated economic life of an intangible asset were to change, then the amortization period for such asset would be adjusted accordingly. Changes in the estimated useful life of an intangible asset would impact operating costs and expenses prospectively from the date of change. If we determine that an intangible asset's unamortized cost is not recoverable due to impairment, we would be required to reduce the asset's carrying value to its estimated fair value through the recording of a non-cash impairment charge. Any such write-down of the value of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2017 and 2016, the carrying value of our customer relationship and contract-based intangible asset portfolio was $3.69 billion and $3.86 billion, respectively. We recorded $166.9 million, $171.3 million and $174.1 million of amortization expense attributable to intangible assets for the years ended December 31, 2017, 2016 and 2015, respectively. For additional information regarding our intangible assets, see Note 7 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Methods We Employ to Measure the Fair Value of Goodwill and Related Assets

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. Goodwill is not amortized; however, it is subject to annual impairment testing at the end of each fiscal year, and more frequently, if circumstances indicate it is probable that the fair value of goodwill is below its carrying amount. Goodwill impairment testing involves determining the fair value of the associated reporting unit. The fair value of a reporting unit is based on assumptions regarding the future economic prospects of the businesses that make up the reporting unit. Such assumptions include (i) discrete financial forecasts for the associated businesses, which, in turn, rely on management's estimates of operating margins, throughput volumes and similar inputs; (ii) long-term growth rates for cash flows beyond discrete forecast periods; and (iii) appropriate discount rates. If the fair value of a reporting unit (including its inherent goodwill) is less than its carrying value, a non-cash impairment charge to operating costs and expenses is required to reduce the carrying value of goodwill to its implied fair value. At December 31, 2017 and 2016, the carrying value of our goodwill was $5.75 billion.

We did not record any goodwill impairment charges in 2017, 2016 or 2015. Based on our most recent goodwill impairment test at December 31, 2017, each reporting unit's fair value was substantially in excess of its carrying value (i.e., by at least 10%). For additional information regarding our goodwill, see Note 7 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Use of Estimates for Revenues and Expenses

Our use of estimates for certain revenues and expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the time required to compile actual billing information and receive third party data needed to record transactions for financial reporting purposes. One example of our use of estimates is the accrual of an estimate of processing plant revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related plant operating information for a specific period). These estimates reverse in the following month and are offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, we include one month of certain estimated data in our results of operations. Such estimates are generally based on actual volume and price data through the first part of the month and estimated for the remainder of the month.

Changes in facts and circumstances may result in revised estimates and could affect our reported financial statements and accompanying disclosures. If the assumptions underlying our revenue and expense estimates prove to be substantially incorrect, it could result in material adjustments in results of operations between periods. We review our estimates based on currently available information.

For information regarding our revenue recognition policies, see Note 3 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Other Items

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2017 (dollars in millions):

		Payment or Settlement due by Period			
Contractual Obligations	**Total**	**In less than 1 year**	**In 1-3 years**	**In 4-5 years**	**More than 5 years**
Scheduled maturities of debt obligations (1)	$ 24,780.1	$ 2,855.7	$ 3,000.0	$ 1,225.0	$ 17,699.4
Estimated cash payments for interest (2)	$ 23,942.0	$ 1,082.9	$ 1,986.3	$ 1,796.8	$ 19,076.0
Operating lease obligations (3)	$ 413.3	$ 57.0	$ 100.0	$ 71.3	$ 185.0
Purchase obligations: (4)					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$ 1,911.5	$ 615.1	$ 963.5	$ 332.9	$ --
NGLs	$ 99.0	$ 69.6	$ 29.4	$ --	$ --
Crude oil	$ 7,891.3	$ 1,352.3	$ 2,286.8	$ 1,456.8	$ 2,795.4
Petrochemicals and refined products	$ 632.1	$ 411.9	$ 220.2	$ --	$ --
Other	$ 33.3	$ 9.3	$ 16.9	$ 4.9	$ 2.2
Underlying major volume commitments:					
Natural gas (in TBtus)	812	265	407	140	--
NGLs (in MMBbls)	7	5	2	--	--
Crude oil (in MMBbls)	471	38	106	94	233
Petrochemicals and refined products (in MMBbls)	11	7	4	--	--
Service payment commitments (5)	$ 398.0	$ 98.3	$ 144.5	$ 87.9	$ 67.3
Capital expenditure commitments (6)	$ 171.6	$ 171.6	$ --	$ --	$ --
Other long-term liabilities (7)	$ 578.4	$ --	$ 370.0	$ 22.4	$ 186.0
Total contractual payment obligations	$ 60,850.6	$ 6,723.7	$ 9,117.6	$ 4,998.0	$ 40,011.3

(1) Represents scheduled future maturities of our consolidated debt principal obligations. For information regarding our consolidated debt obligations, see Note 8 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

(2) Estimated cash payments for interest are based on the principal amount of our consolidated debt obligations outstanding at December 31, 2017, the contractually scheduled maturities of such balances, and the applicable fixed or variable interest rates paid during 2017. With respect to our variable-rate debt obligations, we applied the weighted-average interest rate paid during 2017 to determine the estimated cash payments. See Note 8 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for the weighted-average variable interest rates charged in 2017. In general, our estimated cash payments for interest are significantly influenced by the long-term maturities of our junior subordinated notes (due August 2066 through August 2077). Our estimated cash payments for interest with respect to each junior subordinated note are based on the current interest rate for each note applied to the entire remaining term through the respective maturity date.

(3) Primarily represents land held pursuant to right-of-way agreements and property leases, leases of underground salt dome caverns for the storage of natural gas and NGLs, the lease of transportation equipment used in our operations and office space with affiliates of EPCO.

(4) Represents enforceable and legally binding agreements to purchase goods or services as of December 31, 2017. The estimated payment obligations are based on contractual prices in effect at December 31, 2017 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.

(5) Primarily represents our unconditional payment obligations under firm pipeline transportation contracts.

(6) Represents unconditional payment obligations for services to be rendered or products to be delivered in connection with our capital spending program, including our share of the capital spending of our unconsolidated affiliates.

(7) As reflected on our consolidated balance sheet at December 31, 2017, "Other long-term liabilities" primarily represent the Liquidity Option Agreement, the noncurrent portion of asset retirement obligations and deferred revenues.

In connection with the agreements to acquire EFS Midstream, we are obligated to spend up to an aggregate of $270 million on specified midstream gathering assets for PXD and Reliance, if requested by these producers, over a ten-year period. If constructed, these new assets would be owned by us and be a component of the EFS Midstream System. As of December 31, 2017, we have spent approximately $151 million of the $270 million commitment. Due to the uncertain timing of the remaining potential capital expenditures, we have excluded this amount from the preceding table.

For additional information regarding our significant contractual obligations, see Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Off-Balance Sheet Arrangements

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

Related Party Transactions

For information regarding our related party transactions, see Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Insurance Matters

For information regarding insurance matters, see Note 18 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Regulation

For information regarding the impact of federal, state or local regulatory measures on our business, see "Regulatory Matters" included under Part I, Item 1 and 2 of this annual report.

Recent Accounting Developments

For information regarding recent accounting developments involving revenue recognition and leases, see Note 2 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Item 7A. *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 Consolidated Financial Statements included under Part II, Item 8 of this annual 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 December 31, 2017 (volume measures as noted):

	Volume (1)		Accounting
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Octane enhancement:			
Forecasted purchase of NGLs (MMBbls)	1.1	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	1.0	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	1.0	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	3.9	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	49.0	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	64.6	n/a	Cash flow hedge
NGLs inventory management activities (MMBbls)	0.5	n/a	Fair value hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.6	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.3	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.5	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	3.7	3.3	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	6.9	3.3	Cash flow hedge
Petrochemical marketing:			
Forecasted purchases of NGLs for propylene marketing activities (MMBbls)	0.8	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	67.3	9.0	Mark-to-market
NGL risk management activities (MMBbls) (4)	18.3	n/a	Mark-to-market
Refined products risk management activities (MMBbls) (4)	0.6	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	104.0	12.2	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, May 2018 and December 2020, respectively.
(3) Current and long-term volumes include 21.1 Bcf and 5.3 Bcf, respectively, of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
(4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

At December 31, 2017, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging natural gas processing margins and (iii) hedging the fair value of commodity products held in inventory.

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

- The objective of our natural gas processing hedging program is to hedge an amount of earnings associated with these activities. We achieve this objective by executing fixed-price sales for a portion of our expected equity NGL production using derivative instruments and related contracts. For certain natural gas processing contracts, the hedging of expected equity NGL production also involves the purchase of natural gas for 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 fair value of our natural gas marketing portfolio at the dates indicated (dollars in millions):

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2016**	**December 31, 2017**	**January 31, 2018**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (5.3)	$ (13.9)	$ (6.0)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(9.7)	(16.9)	(6.4)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(0.9)	(10.8)	(5.6)

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

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2016**	**December 31, 2017**	**January 31, 2018**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (150.3)	$ (76.4)	$ (35.7)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(227.7)	(126.1)	(54.1)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(73.0)	(26.8)	(17.3)

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

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2016**	**December 31, 2017**	**January 31, 2018**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (42.4)	$ (65.5)	$ (32.7)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(80.0)	(109.4)	(79.3)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(4.7)	(21.6)	13.9

Interest Rate Hedging Activities

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

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

Interest rate swaps exchange the stated interest rate paid on a notional amount of existing debt for the fixed or floating interest rate stipulated in the derivative instrument. The following table summarizes our portfolio of interest rate swaps at December 31, 2017 (dollars in millions):

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes OO	10 fixed-to-floating swaps	$750.0	5/2015 to 5/2018	1.65% to 1.87%	Fair value hedge

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

		Interest Rate Swap Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2016	December 31, 2017	January 31, 2018
Fair value assuming no change in underlying interest rates	*Asset (Liability)*	$ (0.8)	$ (1.5)	$ (1.5)
Fair value assuming 10% increase in underlying interest rates	*Asset (Liability)*	(2.0)	(1.8)	(1.8)
Fair value assuming 10% decrease in underlying interest rates	*Asset (Liability)*	0.4	(1.2)	(1.2)

The following table summarizes our portfolio of 30-year forward starting swaps outstanding at December 31, 2017. Forward starting swaps hedge the expected underlying benchmark interest rates related to future issuances of debt.

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

As a result of market conditions in 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 gains totaling $1.5 million for the first quarter of 2018.

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

		Forward Starting Swap Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2016	December 31, 2017	January 31, 2018
Fair value assuming no change in underlying interest rates	*Asset (Liability)*	$ 36.2	$ (0.1)	$ 9.6
Fair value assuming 10% increase in underlying interest rates	*Asset (Liability)*	49.3	13.8	18.8
Fair value assuming 10% decrease in underlying interest rates	*Asset (Liability)*	22.1	(15.1)	(0.2)

Product Purchase Commitments

We have long and short-term purchase commitments for natural gas, NGLs, crude oil, petrochemicals and refined products. The purchase prices that we are obligated to pay under these contracts are based on market prices at the time we take delivery of the volumes. For additional information regarding these commitments, see Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Item 8. *Financial Statements and Supplementary Data*

Our audited consolidated financial statements begin on page F-1 of this annual report.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.*

None.

Item 9A. *Controls and Procedures.*

Disclosure Controls and Procedures

As of the end of the period covered by this annual 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 annual 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 fourth quarter of 2017, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Section 302 and 906 Certifications

The required certifications of Messrs. Teague, Fowler and Bulawa under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 are included as exhibits to this annual report (see Exhibits 31 and 32 under Part IV, Item 15 of this annual report).

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2017

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries, including its Chief Executive Officer, President and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control system was designed to provide reasonable assurance to the management of Enterprise Products Partners L.P. and the Board of Directors of its general partner regarding the preparation and fair presentation of Enterprise Products Partners L.P.'s published financial statements.

Our management assessed the effectiveness of Enterprise Products Partners L.P.'s internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control—Integrated Framework (2013)*. This assessment included a review of the design and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on our assessment, we believe that, as of December 31, 2017, Enterprise Products Partners L.P.'s internal control over financial reporting is effective based on those criteria.

Our Audit and Conflicts Committee is comprised of independent directors who are not officers or employees of our general partner. This committee meets regularly with members of management, internal audit staff and representatives of Deloitte & Touche LLP, which is our independent registered public accounting firm, to discuss the adequacy of Enterprise Products Partners L.P.'s internal controls over financial reporting, consolidated financial statements and the nature, extent and results of the audit effort. Management reviews all of Enterprise Products Partners L.P.'s significant accounting policies and assumptions that affect its results of operations with the Audit and Conflicts Committee. Both the independent registered public accounting firm and our internal auditors have direct access to the Audit and Conflicts Committee without the presence of management.

Deloitte & Touche LLP has issued its attestation report regarding our internal control over financial reporting. That report is included within this Item 9A (see "Report of Independent Registered Public Accounting Firm").

Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this annual report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in their respective capacities indicated below on February 28, 2018.

/s/ A. James Teague

Name: A. James Teague
Title: Chief Executive Officer
of Enterprise Products Holdings LLC

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: President
of Enterprise Products Holdings LLC

/s/ Bryan F. Bulawa

Name: Bryan F. Bulawa
Title: Chief Financial Officer
of Enterprise Products Holdings LLC

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products Holdings LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements as of and for the year ended December 31, 2017, of the Company and our report dated February 28, 2018, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting as of December 31, 2017. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2018

Item 9B. ***Other Information.***

None.

PART III

Item 10. ***Directors, Executive Officers and Partnership Governance.***

Partnership Management

General

The following individuals currently serve as members of the Board of Directors (the "Board") of Enterprise GP: Richard H. Bachmann, Carin M. Barth, W. Randall Fowler, James T. Hackett, Charles E. McMahen, William C. Montgomery, Richard S. Snell, A. James Teague, Harry P. Weitzel and Randa Duncan Williams. Ms. Duncan Williams serves as the non-executive Chairman of the Board, and Mr. Bachmann serves as the non-executive Vice Chairman of the Board.

In addition, Larry J. Casey and Edwin C. Smith serve as "advisory directors" for Enterprise GP, and O.S. Andras serves as an "honorary director." Service as an advisory or honorary director does not confer any of the rights, obligations, liabilities or responsibilities of a director of Enterprise GP (including any power or authority to vote on any matters as a director).

Marquard & Bahls AG ("M&B"), a German corporation and the former parent company of Oiltanking, is entitled to designate a nominee for election to the Board (the "M&B Designee") as long as M&B and its affiliates beneficially own at least 27,403,676 of the common units we issued to M&B and its affiliates in connection with the Oiltanking acquisition. In the event that the M&B Designee becomes unable or unwilling to, or for another reason ceases to, serve as a member of the Board while M&B is entitled to maintain the M&B Designee, M&B may designate another person reasonably acceptable to the Board as a replacement. The initial M&B Designee, Dr. F. Christian Flach, resigned from the Board in November 2017. No replacement for Dr. Flach has been nominated by M&B as of the filing date of this annual report.

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for our management, administrative or operating functions. Pursuant to the ASA with EPCO, these roles are performed by employees of EPCO, which are under the direction of the Board and executive officers of Enterprise GP. The executive officers of Enterprise GP are elected for one-year terms and may be removed, with or without cause, only by the Board. Our unitholders do not elect the officers or directors of Enterprise GP. The DD LLC Trustees, through their control of Enterprise GP, have the ability to elect, remove and replace at any time, all of the officers and directors of our general partner. Each member of the Board of Enterprise GP serves until such member's death, resignation or removal. The employees of EPCO who served as directors of our general partner during 2017 were Ms. Duncan Williams and Messrs. Bachmann, Fowler, Teague and Weitzel.

Notwithstanding any contractual limitation on its obligations or duties, Enterprise GP is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to Enterprise GP. Whenever possible, Enterprise GP intends to make any such indebtedness or other obligations non-recourse to itself.

Under our limited partnership agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events, any director or officer, or while serving as director or officer, any person who is or was serving as a tax matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates. Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events, any person who is or was an employee (other than an officer) or agent of our general partner.

Office of the Chairman

The Office of the Chairman is a management oversight group comprised of four individuals: Ms. Duncan Williams (as Chairman of the Board), Mr. Bachmann (as Vice Chairman of the Board), Mr. Teague (as CEO) and Mr. Fowler (as President). The purpose of the Office of the Chairman is for the group to serve collectively as a liaison to the Board and senior management with respect to, and to provide the Chairman, Vice-Chairman, CEO and President a venue to discuss, certain matters including:

- the strategic direction of Enterprise (including business opportunities through organic growth and acquisitions);
- the vision, leadership and development of the management team;
- business goals and operational performance; and
- strategies to preserve our financial strength.

In addition, the Office of the Chairman assists the Board and its Governance Committee in identifying director education opportunities and in determining the size and composition of the Board and recruitment of new members. The Office of the Chairman also oversees policies that (i) reflect our values and business goals and (ii) enhance the effectiveness of our governance structure. The Office of the Chairman also collectively oversees and provides strategic direction for our legal and human resources departments.

In her role as Chairman of the Board (a non-executive role), Ms. Duncan Williams is responsible for, among other things: (i) presiding over and setting the agendas for meetings of the Board, with due consideration of our values and business goals and an effective governance structure; (ii) overseeing the appropriate flow of information to the Board; (iii) acting as a liaison between the Board and senior management; and (iv) meeting regularly with the CEO and the President, the Vice Chairman of the Board and other Board members to review our strategic direction.

In his role as Vice Chairman of the Board (a non-executive role), Mr. Bachmann is responsible for, among other things: (i) assisting the Chairman of the Board in the execution of the Chairman of the Board's functions and responsibilities, as requested from time to time by the Chairman of the Board; and (ii) meeting regularly with the CEO and the President, the Chairman of the Board and other Board members to review our strategic direction.

In his role as CEO, Mr. Teague is our principal executive officer and is responsible for, among other things: (i) managing our overall business strategy and day-to-day operations; (ii) overseeing and providing strategic direction for us, subject to Board approval, in the areas of operations, commercial activities, business development, and health and safety; and (iii) providing the required certifications as principal executive officer of Enterprise GP in connection with our disclosure controls and procedures and internal control over financial reporting.

In his role as President, Mr. Fowler is one of two principal financial officers of Enterprise GP and is responsible for, among other things: (i) managing our overall financial strategy; (ii) overseeing and providing strategic direction for us, subject to Board approval, in the areas of accounting, risk management, finance, treasury and cash management, information technology, investor relations, governmental affairs, and public relations and (iii) providing the required certifications as a co-principal financial officer of Enterprise GP (together with the Chief Financial Officer, or "CFO") in connection with our disclosure controls and procedures and internal control over financial reporting.

Directors and Executive Officers of Enterprise GP

The following table sets forth the name, age and position of each of the directors, excluding advisory or honorary directors, and executive officers of Enterprise GP at February 28, 2018. Each executive officer holds the same respective office shown below in the managing member of EPO.

Name	Age	Position with Enterprise GP
Randa Duncan Williams (1,2,6)	56	Director and Chairman of the Board
Richard H. Bachmann (1,6)	65	Director and Vice Chairman of the Board
A. James Teague (1,6,7,8)	72	Director and CEO
W. Randall Fowler (1,6,7,8)	61	Director and President
Carin M. Barth (2,6)	55	Director
James T. Hackett (2,3,6)	64	Director
Charles E. McMahen (4,5)	78	Director
William C. Montgomery (4)	56	Director
Richard S. Snell (4,6)	75	Director
Harry P. Weitzel (6,8)	53	Director and Senior Vice President, General Counsel and Secretary
Graham W. Bacon (8)	54	Executive Vice President
William Ordemann (8)	58	Executive Vice President
R. Daniel Boss (8)	42	Senior Vice President (Accounting and Risk Control)
Bryan F. Bulawa (8)	48	Senior Vice President and CFO
Brent B. Secrest (8)	45	Senior Vice President
Michael W. Hanson (8)	50	Vice President and Principal Accounting Officer

(1) Member of Office of the Chairman
(2) Member of the Governance Committee
(3) Chairman of the Governance Committee
(4) Member of the Audit and Conflicts Committee
(5) Chairman of the Audit and Conflicts Committee
(6) Member of the Capital Projects Committee
(7) Co-Chairman of the Capital Projects Committee
(8) Executive officer

The following information presents a brief history of the business experience of our directors and executive officers:

Randa Duncan Williams
Ms. Duncan Williams was elected Chairman of the Board of Enterprise GP in February 2013 and a director of Enterprise GP in November 2010. She also serves as a member of Enterprise GP's Governance Committee and Capital Projects Committee. She was elected Chairman of EPCO in May 2010, having previously served as Group Co-Chairman since 1994. Ms. Duncan Williams has served as a director of EPCO since February 1991. She also served as a director of the general partner of Enterprise GP Holdings L.P. ("Holdings GP") from May 2007 to November 2010.

Prior to joining EPCO in 1994, Ms. Duncan Williams practiced law with the firms Butler & Binion and Brown, Sims, Wise & White. Ms. Duncan Williams previously served on the board of directors of Encore Bancshares from July 2007 until July 2012. She currently serves on the board of trustees for numerous charitable organizations. Ms. Duncan Williams is the daughter of the late Mr. Dan L. Duncan, our founder.

Richard H. Bachmann
Mr. Bachmann was elected a director and Vice Chairman of the Board of Enterprise GP in January 2016 and serves as a member of its Capital Projects Committee. He previously served as a director of Enterprise GP from November 2010 through April 2014. He served as an Executive Vice President of Holdings GP from April 2005 to November 2010 and as a director of Holdings GP from February 2006 to November 2010. He served as Chief Legal Officer and Secretary of Holdings GP from April 2005 to May 2010. Mr. Bachmann served as Executive Vice President and Chief Legal Officer of Enterprise Products GP, LLC ("EPGP," the former general partner of Enterprise) from February 1999 until November 2010 and as Secretary of EPGP from November 1999 to November 2010. He previously served as a director of EPGP from June 2000 to January 2004 and from February 2006 to May 2010.

Mr. Bachmann was elected President and CEO of EPCO in May 2010 and has served as a director since January 1999. He previously served as Secretary of EPCO from May 1999 to May 2010 and as a Group Vice Chairman of EPCO from December 2007 to May 2010. Mr. Bachmann served as a director of DEP Holdings, LLC ("DEP GP"), the general partner of Duncan Energy Partners L.P., from October 2006 to May 2010 and as President and CEO of DEP GP from October 2006 to April 2010.

A. James Teague
Mr. Teague was elected CEO of Enterprise GP in January 2016 and has been a director of Enterprise GP since November 2010. He also serves as Co-Chairman of the Capital Projects Committee. Mr. Teague previously served as the Chief Operating Officer ("COO") of Enterprise GP from November 2010 to December 2015 and served as an Executive Vice President of Enterprise GP from November 2010 until February 2013. He served as an Executive Vice President of EPGP from November 1999 to November 2010 and additionally as a director from July 2008 to November 2010 and as COO from September 2010 to November 2010. In addition, he served as Chief Commercial Officer of EPGP from July 2008 until October 2010. He served as Executive Vice President and Chief Commercial Officer of DEP GP from July 2008 until September 2011. He previously served as a director of DEP GP from July 2008 to May 2010 and as a director of Holdings GP from October 2009 to May 2010. Mr. Teague joined Enterprise in connection with its purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. From 1998 to 1999, Mr. Teague served as President of Tejas Natural Gas Liquids, LLC, then an affiliate of Shell. From 1997 to 1998, he was President of Marketing and Trading for MAPCO, Inc. Mr. Teague also serves on the board of directors of Solaris Oilfield Infrastructure, Inc.

W. Randall Fowler
Mr. Fowler was elected a director of Enterprise GP in September 2011 and serves as Co-Chairman of the Capital Projects Committee. He has served as the President of Enterprise GP since January 2016, having previously served as Chief Administrative Officer from April 2015 to January 2016. He served as Executive Vice President and CFO of Enterprise GP from November 2010 to March 2015 and as Executive Vice President and CFO of EPGP from August 2007 to November 2010. He also served as President and CEO of DEP GP from April 2010 until September 2011 and as Executive Vice President and CFO of DEP GP from August 2007 to April 2010. He served as a director of DEP GP from September 2006 until September 2011.

Mr. Fowler served as Senior Vice President and Treasurer of EPGP from February 2005 to August 2007 and of DEP GP from October 2006 to August 2007. Mr. Fowler also previously served as a director of EPGP and of Holdings GP from February 2006 to May 2010. Mr. Fowler also served as Senior Vice President and CFO of Holdings GP from August 2005 to August 2007. Mr. Fowler was elected Vice Chairman and CFO of EPCO in May 2010. He previously served as President and CEO of EPCO from December 2007 to May 2010 and as its CFO from April 2005 to December 2007.

Mr. Fowler, a Certified Public Accountant (inactive), joined Enterprise as Director of Investor Relations in January 1999. He also serves as Chairman of the Board of the Master Limited Partnership Association (formerly National Association of Publicly Traded Partnerships). Mr. Fowler is on the Advisory Board of Alerian, an independent provider of market intelligence for master limited partnerships ("MLPs"), which includes its benchmark Alerian MLP Index , or AMZ. He also serves on the Advisory Board for the College of Business at Louisiana Tech University.

Carin M. Barth
Ms. Barth was elected a director of Enterprise GP in October 2015 and is a member of its Governance Committee and its Capital Projects Committee. She is co-founder and President of LB Capital Inc., a private equity investment firm established in 1988. She currently serves on the following boards of directors: Black Stone Minerals, L.P., where she is Chair of the Audit Committee and Group 1 Automotive, Inc. Additionally, she is Chairman of the Investment Advisory Committee for the Endowment at Texas Tech University, a Trustee of The Welch Foundation and a board member of the Ronald McDonald House of Houston.

Ms. Barth previously served on the Housing Commission at the Bi-Partisan Policy Center in Washington, DC from 2011 to 2014, and was a Commissioner of the Texas Department of Public Safety from 2008 to 2014. She also served as a board member of the following: Bill Barrett Corporation from June 2012 to May 2016; Western Refining Inc., where she was Chair of the Audit Committee from March 2006 to January 2016; Methodist Hospital Research Institute from 2007 to 2012; Encore Bancshares, Inc. from 2009 to 2012; Amegy Bancorporation, Inc. from 2006 to 2009; the Texas Public Finance Authority from 2006 to 2008; and the Texas Tech University System Board of Regents from 1999 to 2005. She was appointed by President George W. Bush to serve as CFO of the U.S. Department of Housing and Urban Development from 2004 to 2005.

James T. Hackett
Mr. Hackett was elected a director of Enterprise GP in April 2014 and serves as Chairman of its Governance Committee and as a member of its Capital Projects Committee. Mr. Hackett is a partner with Riverstone Holdings LLC, a private energy investment firm. Mr. Hackett serves as Executive Chairman of Alta Mesa Resources, Inc. (formerly named Silver Run Acquisition Corporation II) and Chief Operating Officer of Kingfisher Midstream, LLC, an affiliate of Alta Mesa engaged in providing certain midstream energy services, including crude oil and gas gathering, processing and marketing to producers of natural gas, natural gas liquids, crude oil and condensate. Mr. Hackett served as Executive Chairman of the board of directors of Anadarko Petroleum Corporation ("Anadarko"), one of the world's largest independent oil and natural gas exploration and production companies, from 2012 to 2013 after serving as its CEO from 2003 to 2012 and Chairman of the Board from 2006 to 2012. He also served as Anadarko's President from 2003 to 2010. Mr. Hackett is a board member of Flour Corp. and NOV, Inc. as well as Sierra Oil & Gas and Talen Energy (portfolio companies of Riverstone). He is a former director of Bunge Ltd. and the former Chairman of the Board of the Federal Reserve Bank of Dallas. He is a past Chairman of the National Petroleum Council, a member of the Society of Petroleum Engineers, a member of the Baylor College of Medicine Board of Trustees and a member of the Rice University Board of Trustees. Mr. Hackett is also a former adjunct Professor of Finance at Rice University.

Charles E. McMahen
Mr. McMahen was elected a director of Enterprise GP in November 2010 and serves as Chairman of its Audit and Conflicts Committee. He served as a director of Holdings GP from August 2005 to November 2010. Mr. McMahen served as Vice Chairman of Compass Bank from March 1999 until December 2003 and served as Vice Chairman of Compass Bancshares from April 2001 until his retirement in December 2003. Mr. McMahen also served as Chairman and CEO of Compass Banks of Texas from March 1990 until March 1999. Mr. McMahen has served as a director of Compass Bancshares, and its successor, BBVA Compass Bank (a wholly owned subsidiary of BBVA), since 2001. He also serves as a director for BBVA Compass Bancshares, Inc. (a wholly owned subsidiary of BBVA and a bank holding company for BBVA's North American banking operations). Mr. McMahen serves on the Audit Committee for BBVA Compass Bancshares, Inc. and as Chairman of its Risk Committee. Mr. McMahen served as Chairman of the Board of Regents of the University of Houston from September 1998 to August 2000.

William C. Montgomery
Mr. Montgomery was elected a director of Enterprise GP in October 2015 and is a member of its Audit and Conflicts Committee. He has served as a Partner of Quantum Energy Partners since 2011 and is also a member of its Executive and Investment Committees. He is responsible for originating and overseeing investments in the oil and gas upstream and oilfield service sectors. Prior to joining Quantum Energy Partners, Mr. Montgomery was a Partner in the Investment Banking Division of Goldman, Sachs & Co. where, during his tenure, he headed the firm's Americas Natural Resources Group as well as its Houston office. His career as a banker spanned 22 years and was focused on large cap energy companies primarily in the upstream and oil service sectors. He also serves on the board of Apache Corporation. Mr. Montgomery has been an active civic leader, chairing the boards of The Houston Museum of Natural Science and The St. Francis Episcopal Day School and currently serves on the board of trustees of The Kinkaid School, The Episcopal Health Foundation and the Board of Visitors of the MD Anderson Cancer Center.

Richard S. Snell

Mr. Snell, a Certified Public Accountant, was elected a director of Enterprise GP in September 2011 and is a member of its Audit and Conflicts Committee and its Capital Projects Committee. He previously served as a director of DEP GP from January 2010 to September 2011 and as a director of the general partner of TEPPCO Partners, L.P. from January 2006 until October 2009. From June 2000 until February 2006, he served as a director of EPGP. He is of counsel with the law firm of Ytterberg Deery Knull LLP, having been with the firm since late January 2017. Mr. Snell previously served as an attorney with the law firms of Thompson & Knight LLP (from 2000 to early 2017) and Snell & Smith, P.C. (from its founding in 1993 until 2000).

Harry P. Weitzel

Mr. Weitzel was elected a director of Enterprise GP and as a member of its Capital Projects Committee in November 2016 and has served as Senior Vice President, General Counsel and Secretary of Enterprise GP since April 2016. He previously served as Senior Vice President, Deputy General Counsel and Secretary of Enterprise GP from January 2015 to April 2016. Mr. Weitzel is currently responsible for all legal functions of Enterprise, including securities, litigation, employment, mergers and acquisitions, and commercial transactions. Mr. Weitzel has extensive experience as a commercial litigator, having practiced over 24 years in Texas and California. He has successfully represented individual, corporate and governmental clients as plaintiffs and defendants in a wide variety of business-related matters. Mr. Weitzel has tried cases in state and federal courts, as well as arbitrations under the American Arbitration Association, JAMS and the International Chamber of Commerce. He has handled appeals in state and federal courts. Prior to joining Enterprise, Mr. Weitzel was a commercial litigation partner with Pepper Hamilton LLP in Irvine, California from October 2009 to December 2014.

Graham W. Bacon

Mr. Bacon was elected Executive Vice President (Operations and Engineering) of Enterprise GP in October 2015. He previously served as Group Senior Vice President (Operations and Environmental, Health, Safety & Training) from February 2014 to October 2015; as Senior Vice President (Operations) from January 2012 to February 2014; as Vice President (Operations) from June 2006 to January 2012, and as Vice President (Engineering) from September 2005 to May 2006. He joined Enterprise in 1991 and has held a variety of operations and engineering roles. Prior to joining Enterprise, Mr. Bacon worked for Vista Chemical Company.

William Ordemann

Mr. Ordemann was elected Executive Vice President (Commercial) of Enterprise GP in October 2015, having previously served as Group Senior Vice President (Unregulated Liquids, Crude and Natural Gas Services) from April 2012 to October 2015. He served as Executive Vice President of Enterprise GP from August 2007 to April 2012. He served as COO of EPGP from August 2007 until September 2010 and as its Executive Vice President from August 2007 to November 2010. He was also elected an Executive Vice President of DEP GP in August 2007 and served in such role until September 2011. Mr. Ordemann previously served as a Senior Vice President of EPGP from September 2001 to August 2007 and was a Vice President of EPGP from October 1999 to September 2001. He joined Enterprise in connection with its purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. He also served as a director of Oiltanking GP from October 2014 until February 2015 and is a director of the GPA Midstream Association, where he serves on the Executive Committee as Chairman-Elect. Mr. Ordemann will assume the role of Chairman of that association in April 2018.

R. Daniel Boss

Mr. Boss was elected Senior Vice President (Accounting and Risk Control) of Enterprise GP in August 2016. Mr. Boss served as a Senior Vice President of Enterprise GP from March 2015 to August 2016 with responsibility over our regulated business. He also served as Vice President (Risk Control) from April 2013 to March 2015 and as Senior Director (Risk Control) from January 2010 to March 2013. While serving in these positions, Mr. Boss was Chairman of the Risk Management Committee and had responsibilities for our marketing risk management policies, transaction controls and derivatives and hedging strategies compliance. Mr. Boss also served as Director (Volume Accounting) from November 2008 until January 2010 where he was responsible for gas marketing and commodity derivatives accounting, hedging and reporting. Prior to joining Enterprise, Mr. Boss held leadership positions with Merrill Lynch Commodities and Dynegy Inc.

Bryan F. Bulawa
Mr. Bulawa was elected Senior Vice President and CFO of Enterprise GP in April 2015. He also served as Senior Vice President and Treasurer of Enterprise GP from October 2009 to March 2015, Senior Vice President, CFO and Treasurer of DEP GP from April 2010 to September 2011 and as a Director of DEP GP from February 2011 to September 2011. He previously served as Senior Vice President and Treasurer of EPGP from October 2009 to November 2010, as Senior Vice President and Treasurer of DEP GP from October 2009 to April 2010, and as Vice President and Treasurer of EPGP from July 2007 to October 2009. He has also served as Senior Vice President and CFO of EPCO since April 2015, having previously served as Senior Vice President and Treasurer from May 2010 to March 2015. Mr. Bulawa also served as Chairman of the Board for Oiltanking GP from October 2014 to February 2015. Prior to joining Enterprise, Mr. Bulawa spent 13 years at Scotia Capital, where he last served as director of the firm's U.S. Energy Corporate Finance and Distribution group.

Brent B. Secrest
Mr. Secrest was elected Senior Vice President (Liquid Hydrocarbons Marketing) of Enterprise GP in May 2016. He has responsibility for our NGL, crude oil and refined products marketing activities. Mr. Secrest previously served as Vice President (Crude Oil and Refined Products Marketing) from October 2015 to May 2016 and as Vice President (Crude Oil Pipelines and Terminals) from October 2012 to October 2015. He has also served Enterprise in various other leadership positions, including in the areas of NGL marketing and supply, commercial development, distribution, and business analysis. Mr. Secrest has over 20 years of experience in the energy industry and began his career at Basis Petroleum Inc. prior to joining Enterprise in 1996.

Michael W. Hanson
Mr. Hanson was elected a Vice President (Financial Reporting) and Principal Accounting Officer of Enterprise GP in August 2016. He has served as a Vice President of Enterprise GP since April 2011 with responsibility over Enterprise's financial and management reporting group within its Accounting department. He has served Enterprise and its affiliates in various accounting roles since 1992, including as an Assistant Controller since April 2007 and Director of Financial Reporting from November 2004 to March 2007. Mr. Hanson's responsibilities include team leadership in the preparation of Enterprise's quarterly and annual reports. Mr. Hanson continues to lead Enterprise's financial and management reporting group and reports to Mr. Boss, who has overall team leadership of the Accounting department.

Director Experience, Qualifications, Attributes and Skills

The following is a brief discussion of the experience, qualifications, attributes or skills that led to the conclusion that each of the following persons should serve as a director of our general partner.

Five of our directors are current employees of EPCO and officers of our general partner or its affiliates. Each of these directors has significant experience in our industry as executive officers as well as other qualifications, attributes and skills. These include:

- for Ms. Duncan Williams, legal and community involvement with numerous charitable organizations, and active involvement in EPCO's businesses, including ownership in and management of our businesses;

- for Mr. Teague, over 40 years of commercial management of midstream assets and marketing and trading activities, both for third parties and for us;

- for Mr. Fowler, approximately 20 years of experience with our midstream assets, including finance, accounting and investor relations and, for over the last ten years, as a member of our executive management team;

- for Mr. Bachmann, over 30 years of experience with our midstream assets, including legal, regulatory, contracts and mergers and acquisitions and, for over the last 19 years, as a member of either EPCO's or our executive management teams; and

- for Mr. Weitzel, over 25 years of experience in Texas and California as a commercial litigator, having successfully represented individual, corporate and governmental clients as plaintiffs and defendants in a wide variety of business-related matters.

Our five outside voting directors also have significant experience in a variety of capacities, as well as other qualifications, attributes and skills. These include:

- for Ms. Barth, executive management experience in various financial and governance roles;

- for Mr. Hackett, executive management of a major oil and gas exploration and production company;

- for Mr. McMahen, executive management experience in banking and finance;

- for Mr. Montgomery, executive management of both an investment banking firm and a private equity investment firm serving the global energy industry; and

- for Mr. Snell, professional experience involving complex legal and accounting matters.

As advisory directors, Mr. Casey has executive management experience in NGL and petrochemicals trading and related storage businesses and Mr. Smith has experience in banking and investment matters. As an honorary director, Mr. Andras has a long history with Enterprise and its operations, including being a former CEO.

Partnership Governance

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals and maintain the trust and confidence of investors, employees, suppliers, business partners and other stakeholders.

A key element of strong governance is having independent members of the Board. Pursuant to the NYSE listing standards, a director will be considered independent if the Board determines that he or she does not have a material relationship with Enterprise GP or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with Enterprise GP or us). Based on the foregoing, the Board has affirmatively determined that Ms. Barth and Messrs. Hackett, McMahen, Montgomery and Snell are independent directors under the NYSE rules.

Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, we are not required to comply with certain NYSE rules. In particular, we are not required to comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of our general partner be comprised of a majority of independent directors. Currently, five of the ten Board members of Enterprise GP are independent under NYSE rules; however, this composition may not always be in effect. Also, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of Enterprise GP maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Code of Conduct and Ethics and Corporate Governance Guidelines

Enterprise GP has adopted a "Code of Conduct" that applies to its directors, officers and employees. This code sets forth our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance on complying with the code, the reporting of compliance issues, and discipline for violations of the code. The Code of Conduct also establishes policies applicable to our CEO, President, CFO, Principal Accounting Officer and senior financial and other managers to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications, and prompt internal reporting of violations of the code (and thus accountability for adherence to the code). Employees are required to certify their understanding and compliance with the Code of Conduct on an annual basis. Training on Code of Conduct is also provided to employees, where applicable.

Governance guidelines, together with applicable committee charters, provide the framework for effective governance of our partnership. The Board has adopted the "*Governance Guidelines of Enterprise Products Partners*," which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibilities of the Audit and Conflicts Committee and the Governance Committee, the conduct and frequency of Board and committee meetings, management succession plans, director access to management and outside advisors, director compensation, director and executive officer equity ownership, director orientation and continuing education, and annual self-evaluation of the Board. The Board recognizes that effective governance is an on-going process, and thus, it will review the Governance Guidelines of Enterprise Products Partners annually or more often as deemed necessary.

Audit and Conflicts Committee

The purpose of the Board's Audit and Conflicts Committee is to address audit and conflicts-related matters. In accordance with NYSE rules and the Securities Exchange Act of 1934, the Board has named three of its members to serve on the Audit and Conflicts Committee. Members of the Audit and Conflicts Committee must have a basic understanding of finance and accounting matters and be able to read and understand fundamental financial statements, and at least one member of the Audit and Conflicts Committee shall have accounting or related financial management expertise. The current members of the Audit and Conflicts Committee are Messrs. McMahen, Montgomery and Snell, all of whom are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment. The Board has affirmatively determined that Mr. McMahen satisfies the definition of "*Audit Committee Financial Expert*" as defined in Item 407(d)(5) of Regulation S-K promulgated by the SEC.

The primary responsibilities of the Audit and Conflicts Committee include (i) reviewing potential conflicts of interest, including related party transactions, (ii) monitoring the integrity of our financial reporting process and related systems of internal control, (iii) ensuring our legal and regulatory compliance and that of Enterprise GP, (iv) overseeing the independence and performance of our independent public accountant, (v) approving all services performed by our independent public accountant, (vi) providing for an avenue of communication among the independent public accountant, management, internal audit function and the Board, (vii) encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels, (viii) reviewing areas of potential significant financial risk to our businesses and (ix) approving awards granted under long-term incentive plans.

If the Board believes that a particular matter presents a conflict of interest and proposes a resolution, the Audit and Conflicts Committee has the authority to review such matter to determine if the proposed resolution is fair and reasonable to us. Any matters approved by the Audit and Conflicts Committee are conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by Enterprise GP or the Board of any duties they may owe us or our unitholders.

Pursuant to its formal written charter, the Audit and Conflicts Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. The Audit and Conflicts Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Governance Committee

The primary purpose of the Governance Committee is to develop and recommend to the Board a set of governance guidelines applicable to our partnership, to review such guidelines from time to time and to oversee governance matters related to our business, including Board and Committee composition, qualifications of Board candidates, director independence, succession planning and related matters. The Governance Committee also assists in Board oversight of management's establishment and administration of our environmental, health and safety policies, procedures, programs and initiatives, and related matters. In accordance with its charter, the Governance Committee shall be composed of not less than three members, at least a majority of whom shall be independent directors. Currently, the Governance Committee is comprised of Ms. Duncan Williams and two independent directors (Ms. Barth and Mr. Hackett).

Like the Audit and Conflicts Committee, the Governance Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. In addition, the Governance Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Capital Projects Committee

The primary purpose of the Capital Projects Committee is to review and approve certain expenditures by Enterprise GP, Enterprise and/or their respective consolidated subsidiaries in connection with proposed capital projects. Currently, the Capital Projects Committee is comprised of Ms. Duncan Williams, Ms. Barth and Messrs. Bachmann, Fowler, Hackett, Snell, Teague and Weitzel. Messrs. Teague and Fowler are co-chairmen of the Capital Projects Committee.

Investor Access to Corporate Governance Information

We provide investors access to information relating to our governance procedures and principles, including the Code of Conduct, Governance Guidelines, the charters of the Audit and Conflicts Committee, the Governance Committee and the Capital Projects Committee, along with other information, through our website, www.enterpriseproducts.com. You may also contact our Investor Relations department at (866) 230-0745 for printed copies of these documents free of charge.

NYSE Corporate Governance Listing Standards

On April 3, 2017, Mr. Teague certified to the NYSE (as required by Section 303A.12(a) of the NYSE Listed Company Manual) that he was not aware of any violation by us of the NYSE's Corporate Governance listing standards as of that date.

Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the "presiding director," who is responsible for leading and facilitating such executive sessions. Currently, the presiding director is Mr. McMahen.

Confidential Telephone Hotline

In accordance with NYSE rules, we have established a toll-free, confidential telephone hotline (the "Hotline") so that interested parties may communicate with the presiding director or with all the non-management directors as a group. All calls to this Hotline are reported to the chairman of the Audit and Conflicts Committee, who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential Hotline is (877) 888-0002.

Section 16(a) Beneficial Ownership Reporting Compliance

Under federal securities laws, directors and executive officers of Enterprise GP and any persons holding more than 10% of our common units are required to report their beneficial ownership of common units and any changes in their beneficial ownership levels to us and the SEC. Specific due dates for these reports have been established by regulation, and we are required to disclose in this annual report any failure to file this information within the specified timeframes. All such reporting was done in a timely manner in 2017, except that the vesting of a phantom unit award for Mr. Weitzel (and payment of the related tax liability by withholding securities incident to such vesting) was reported on a Form 4 filed on January 17, 2017, instead of by the reporting deadline of January 9, 2017.

Item 11. *Executive Compensation.*

Executive Officer Compensation

We do not directly employ any of the persons responsible for managing our business. Instead, we are managed by our general partner, the executive officers of which are employees of EPCO. Our management, administrative and operating functions are primarily performed by employees of EPCO in accordance with the ASA. Pursuant to the ASA, we reimburse EPCO for all of its compensation costs related to the employment of personnel working on our behalf. For information regarding the ASA, see Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Summary Compensation Table

The following table presents total compensation amounts paid, accrued or otherwise expensed by us with respect to (i) our principal executive officer, (ii) our principal financial officers and (iii) the other three highest paid officers of our general partner named below for the year ended December 31, 2017. Collectively, these individuals were our "named executive officers" for 2017. To the extent such individuals were named executive officers in the prior two years, their total compensation for those years is presented as well.

Name and Principal Position	Year	Cash Salary ($)	Bonus ($) (1)	Equity-Based Awards ($) (2)	All Other Compensation ($) (3)	Total ($)
A. James Teague	2017	$ 800,000	$ 2,205,000	$ 4,041,800	$ 651,138	$ 7,697,938
CEO	2016	800,000	2,100,000	3,989,926	606,309	7,496,235
(Principal Executive Officer)	2015	793,750	1,800,000	4,108,628	550,701	7,253,079
W. Randall Fowler	2017	525,000	1,181,250	2,425,080	374,191	4,505,521
President	2016	521,178	984,375	2,701,298	328,999	4,535,850
(Principal Financial Officer)	2015	459,375	581,250	2,042,400	285,691	3,368,716
Bryan F. Bulawa	2017	314,500	267,750	922,685	182,157	1,687,092
Senior Vice President and CFO	2016	314,500	245,438	1,292,173	143,905	1,996,016
(Principal Financial Officer)	2015	306,000	233,750	810,152	122,214	1,472,116
William Ordemann	2017	451,150	367,500	1,674,460	302,070	2,795,180
Executive Vice President,	2016	451,150	357,000	1,891,366	230,291	2,929,807
Commercial	2015	447,400	340,000	1,198,715	184,258	2,170,373
Graham W. Bacon	2017	393,750	315,000	1,674,460	263,501	2,646,711
Executive Vice President,	2016	375,000	294,000	1,958,576	206,541	2,834,117
Operations and Engineering	2015	320,021	275,000	1,021,200	155,071	1,771,292
Brent B. Secrest	2017	306,750	262,500	1,154,800	378,084	2,102,134
Senior Vice President,						
Liquids Hydrocarbons Marketing						

(1) Amounts represent discretionary annual bonus awards earned by each named executive officer with respect to the year presented. Bonuses awarded for the year ended December 31, 2015 were paid in cash in February 2016. For the years ended December 31, 2017 and 2016, the dollar value of each officer's discretionary bonus (less any retirement plan deductions and withholding taxes) was remitted through the issuance of an equivalent value of newly issued Enterprise common units in February of the respective following year.

(2) Amounts represent our estimated share of the aggregate grant date fair value of equity-based awards granted during each year presented. Amounts presented for the year ended December 31, 2016 reflect the grant of phantom unit and profits interest awards to each named executive officer. Amounts presented for the years ended December 31, 2017 and 2015 reflect grants of phantom unit awards to each named executive officer.

(3) Amounts include (i) contributions in connection with funded, qualified, defined contribution retirement plans, (ii) quarterly distributions paid on equity-based awards, (iii) the imputed value of life insurance premiums paid on behalf of the officer, (iv) employee retention payments and (v) other amounts.

The following table presents the components of "All Other Compensation" for each named executive officer for the year ended December 31, 2017:

Named Executive Officer	Contributions Under Funded, Qualified, Defined Contribution Retirement Plans	Quarterly Distributions Paid On Equity-Based Awards (1)	Life Insurance Premiums	Other	Total All Other Compensation
A. James Teague	$ 29,700	$ 607,802	$ 7,663	$ 5,973	$ 651,138
W. Randall Fowler	22,275	345,179	3,267	3,470	374,191
Bryan F. Bulawa (2)	25,245	138,945	842	17,125	182,157
William Ordemann (2)	32,400	233,634	2,838	33,198	302,070
Graham W. Bacon	32,400	222,877	1,518	6,706	263,501
Brent B. Secrest (3)	29,700	93,037	631	254,716	378,084

(1) Reflects aggregate cash payments made to the named executive officer in connection with (i) distribution equivalent rights ("DERs") issued in tandem with phantom unit awards, (ii) distributions paid on restricted common units and (iii) distributions paid in connection with profits interest awards. With respect to DER amounts allocated to us, the following cash payments were made to the named executive officers during the year ended December 31, 2017: Mr. Teague, $580,660; Mr. Fowler, $323,667; Mr. Bulawa, $124,862; Mr. Ordemann, $217,193; Mr. Bacon, $205,596; and Mr. Secrest, $83,328.

(2) Amounts presented as "Other" for Mr. Bulawa and Mr. Ordemann include lump sum payments of $12,750 and $25,000, respectively, paid in April 2017 in lieu of increases in their respective base cash salaries.

(3) Amount presented as "Other" for Mr. Secrest includes a retention payment made pursuant to a retention agreement he entered into with EPCO in January 2014. For further information, please see the discussion of this agreement and payment under "Compensation Discussion and Analysis – Elements of Compensation" below.

Compensation Discussion and Analysis

Elements of Compensation

With respect to our named executive officers, compensation paid or awarded by us reflects only that portion of compensation paid by EPCO and allocated to us pursuant to the ASA, including an allocation of a portion of the cost of long-term incentive plans of EPCO. The elements of EPCO's compensation program, along with EPCO's other incentives (e.g., benefits, work environment and career development), are intended to provide a total rewards package to employees. The objective of EPCO's compensation program is to provide competitive compensation opportunities that will align and drive employee performance toward the creation of sustained long-term unitholder value. We believe that our compensation program allows us to attract, motivate and retain high quality talent with the skills and competencies we require. Our compensation packages are designed to reward contributions by employees in support of the business strategies of EPCO and its affiliates at both our partnership and individual levels and to avoid risks that are likely to conflict with our risk management policies.

For the years ended December 31, 2017 and 2016, the primary elements of compensation for the named executive officers consisted of annual cash base salary, discretionary annual bonus (satisfied principally through the issuance of Enterprise common units), phantom unit and profits interest awards under long-term incentive arrangements and other compensation, including very limited perquisites. For the year ended December 31, 2015, the primary compensation elements consisted of annual cash base salary, discretionary annual cash bonus awards, phantom unit awards and other compensation, including very limited perquisites. With respect to the annual periods presented in the Summary Compensation Table, EPCO's compensation package for the named executive officers did not include any compensation elements based on targeted performance-based criteria. We believe that the absence of targeted performance-based criteria has the effect of discouraging excessive risk taking by our named executive officers.

Changes in the base salaries of our named executive officers during the three years ending December 31, 2017 were largely budget-driven and made consistent relative to increases in the base salaries of our other executive officers.

The bonus awards are discretionary and, in combination with annual base salaries, are intended to yield competitive total compensation levels for the named executive officers and drive performance in support of our business strategies, as well as the performance of other EPCO affiliates for which the named executive officer may perform services. The annual bonus amount presented for each named executive officer reflects a general consideration of our overall financial results for those periods. This consideration takes into account a number of our financial measures (e.g., non-GAAP gross operating margin and distributable cash flow metrics) and our performance relative to peers, without any weight or formula given to any specific financial performance measures. In addition, a subjective judgment of each named executive officer's performance for those periods is taken into account and reflected in the annual bonus amounts. The bonus amounts are also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers.

Each of our named executive officers has been granted equity-based compensation. The amount of equity-based compensation granted to our named executive officers reflects a general consideration of our overall financial performance, along with a subjective judgment of each named executive officer's contribution in support of that performance, without any weight or formula given to any specific financial performance measures. The value of equity-based awards granted to the named executive officers are also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers. Each of the named executive officers received grants of phantom unit awards for the periods presented in the summary compensation table.

In addition, EPCO formed four limited partnerships (generally referred to as "Employee Partnerships") in 2016 to serve as long-term 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"). Each of our named executive officers participates in one of these Employee Partnerships.

EPCO expects to continue its policy of paying for limited perquisites attributable to our named executive officers. EPCO also makes matching contributions under its defined contribution plans for the benefit of our named executive officers in the same manner as it does for other EPCO employees.

EPCO does not offer our named executive officers a defined benefit pension plan. Also, none of our named executive officers had nonqualified deferred compensation during the three years ended December 31, 2017.

In addition to the other elements of compensation, we may use retention agreements as a means to reinforce and encourage the continued dedication of our named executive officers to EPCO and us as members of our executive management team. In January 2017, Mr. Secrest received a cash employee retention payment of $250,000, less applicable tax withholdings. This payment was the second, and final, payment made pursuant to retention agreement that EPCO entered into with Mr. Secrest in January 2014. The agreement provided for a three-year retention period, with an initial payment of $250,000 made in January 2016 and a second payment of $250,000 made in January 2017.

In order to qualify for the retention payments, Mr. Secrest was required to complete 24 months of continuous employment with EPCO (from the effective date of his retention agreement) to receive the first payment, and an additional 12 months of continuous employment to receive the second payment. Since Mr. Secrest devoted all of his time to our affairs since entering into the retention agreement, we were allocated all of the expense associated with these payments. Apart from this retention agreement, none of the named executive officers had employee retention agreements in place during the year ended December 31, 2017.

Overview of Decision-Making Process regarding Compensation of Named Executive Officers

The Audit and Conflicts Committee of our general partner, with input from the EPCO Trustees and EPCO's human resources department, has ultimate decision-making authority with respect to the compensation of our CEO and our President. The compensation of our other named executive officers (other than any equity-based awards under EPCO's long-term incentive plans) is determined by our CEO and our President. Neither EPCO nor our general partner has a separate compensation committee; however, grants of equity-based compensation under EPCO's long-term incentive plans (e.g., phantom unit awards) to our named executive officers, including our CEO and our President, must be approved by the Audit and Conflicts Committee. The issuance of profits interest awards to the named executive officers during 2016 was approved by EPCO's Board of Directors.

The overall compensation of each named executive officer is not based on any formula or specific performance criteria; rather, the Audit and Conflicts Committee, our President, our CEO and EPCO (as applicable) determine an appropriate level and mix of compensation for each officer on a case-by-case basis. Further, there is no established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation. However, some considerations that the Audit and Conflicts Committee or our President and our CEO (as applicable) may take into account in making the case-by-case compensation determinations include the total value of all elements of compensation and the appropriate balance of internal pay equity among our executive officers. The Audit and Conflicts Committee, our President, our CEO and EPCO (as applicable) also consider individual performance, levels of responsibility and value to the organization. All compensation determinations are subjective and discretionary.

In making compensation decisions, EPCO considers market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, relevant compensation surveys and reports. These surveys and reports are conducted and prepared by third party compensation consultants. In 2017, EPCO engaged Meridian Compensation Partners, LLC (the "Consultant") to complete a detailed review of executive compensation relative to our industry. In connection with this review, the Consultant provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry competitors. The market data for industry competitors included information from CenterPoint Energy, Inc.; Dominion Energy, Inc.; Enbridge Inc.; Energy Transfer Partners, L.P.; Kinder Morgan Inc.; Magellan Midstream Partners, L.P.; ONEOK, Inc.; Plains All American Pipeline, L.P.; Spectra Energy Corp.; Sunoco Logistics Partners L.P.; Targa Resources Corporation; The Williams Companies, Inc.; and TransCanada Corporation.

Neither we, nor EPCO, which engages the Consultant, are aware of the specific data of the companies included in the Consultant's proprietary database for specific positions. EPCO uses the information provided in the Consultant's analysis to gauge whether compensation levels reported by the Consultant and the general ranges of compensation for EPCO employees in similar positions are comparable, but that comparison is only a factor taken into consideration and may or may not impact compensation of our named executive officers, for which our Audit and Conflicts Committee (in the case of our President's and our CEO's compensation) or our President and our CEO (in the case of compensation to be paid to our other named executive officers) have the ultimate decision-making authority. EPCO does not otherwise engage in benchmarking for the named executive officers' positions.

Allocation of Compensation between Us and EPCO and its other affiliates

Under the ASA, the compensation costs of our named executive officers, including those costs related to equity-based awards, are allocated between us and other affiliates of EPCO based on the estimated amount of time that each officer spends on our consolidated businesses in any fiscal year. These percentages are reassessed at least quarterly. The following table presents the average approximate amount of time devoted by each of our named executive officers to our consolidated businesses and to EPCO and its other privately held affiliates during each of the years indicated.

Named Executive Officer	Year	Enterprise Products Partners	EPCO and its other affiliates	Total Time Allocated
A. James Teague	2017	100%	--	100%
	2016	100%	--	100%
	2015	100%	--	100%
W. Randall Fowler	2017	75%	25%	100%
	2016	75%	25%	100%
	2015	75%	25%	100%
Bryan F. Bulawa	2017	85%	15%	100%
	2016	85%	15%	100%
	2015	85%	15%	100%
William Ordemann	2017	100%	--	100%
	2016	100%	--	100%
	2015	100%	--	100%
Graham W. Bacon	2017	100%	--	100%
	2016	100%	--	100%
	2015	100%	--	100%
Brent B. Secrest	2017	100%	--	100%

Grants of Equity-Based Awards in Fiscal Year 2017

The following table presents information concerning each grant of an equity-based award in 2017 to a named executive officer for which we will be allocated our pro rata share of the related cost under the ASA.

Award Type/Named Executive Officer	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	Grant Date Fair Value of Equity-Based Awards ($) (1)
Phantom unit awards: (2)					
A. James Teague	02/16/17	--	140,000	--	$ 4,041,800
W. Randall Fowler	02/16/17	--	112,000	--	2,425,080
Bryan F. Bulawa	02/16/17	--	37,600	--	922,685
William Ordemann	02/16/17	--	58,000	--	1,674,460
Graham W. Bacon	02/16/17	--	58,000	--	1,674,460
Brent B. Secrest	02/16/17	--	40,000	--	1,154,800

(1) Amounts presented reflect that portion of grant date fair value allocable to us based on the estimated percentage of time each named executive officer spent on our consolidated business activities during 2017. Based on current allocations, we estimate that the consolidated compensation expense we record for each named executive officer with respect to these awards will equal these amounts over time.

(2) The grant date fair value presented for the phantom unit awards is based, in part, on the closing price of our common units on February 16, 2017 of $28.87 per unit. For information about assumptions utilized in the valuation of these awards, see Note 13 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report, the applicable disclosures of which are incorporated by reference into this Item 11.

Phantom unit awards

The phantom unit awards were granted under the 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) (the "2008 Plan"). 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 December 31, 2017, substantially all of our phantom unit awards are expected to result in the issuance of common units upon vesting; therefore, the applicable awards are accounted for as equity-classified awards.

Each phantom unit award includes a tandem DER, which entitles the holder 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.

Summary of Long-Term Incentive Arrangements Underlying 2017 Award Grants

The 2008 Plan provides for incentive awards to EPCO's key employees and non-employee directors and consultants who perform management, administrative or operational functions for us or our affiliates. Awards granted under the 2008 Plan may be in the form of phantom units, DERs, restricted common units, unit options, unit appreciation rights and other unit-based awards or substitute awards. For information regarding the number of our common units authorized for issuance under the 2008 Plan, see "Securities Authorized for Issuance Under Equity Compensation Plans" under Item 13 of this annual report.

Equity-Based Awards Outstanding at December 31, 2017

The following information summarizes each named executive officer's long-term incentive awards outstanding at December 31, 2017. These amounts are presented on a gross basis and do not reflect any allocation of compensation to affiliates under the ASA.

		Unit Awards	
Award Type/Named Executive Officer	**Vesting Date**	**Number of Units That Have Not Vested (#)** (1)	**Market Value of Units That Have Not Vested ($)** (2)
Phantom unit awards: (3)			
A. James Teague	Various	356,600	$ 9,453,466
W. Randall Fowler	Various	268,212	7,110,300
Bryan F. Bulawa	Various	91,174	2,417,023
William Ordemann	Various	135,000	3,578,850
Graham W. Bacon	Various	129,750	3,439,673
Brent B. Secrest	Various	57,625	1,527,639
Profits interest awards:			
A. James Teague (4)	2/22/20	--	$ 383,703
W. Randall Fowler (5)	2/22/21	--	532,803
Bryan F. Bulawa (6)	2/22/21	--	388,332
William Ordemann (4)	2/22/20	--	383,703
Graham W. Bacon (4)	2/22/20	--	438,517
Brent B. Secrest (6)	2/22/21	--	242,708

(1) Represents the total number of phantom unit awards outstanding for each named executive officer.
(2) With respect to amounts presented for phantom unit awards, the market values were derived by multiplying the total number of each award type outstanding for the named executive officer by the closing price of our common units on December 29, 2017 (the last trading day of 2017) of $26.51 per unit. With respect to amounts presented for the profits interest awards, amount represents the estimated liquidation value to be received by the named executive officer based on the closing price of our common units on December 29, 2017 and the terms of liquidation outlined in the applicable Employee Partnership agreement.
(3) Of the 1,038,361 phantom unit awards presented in the table, the vesting schedule is as follows: 392,136 in 2018; 305,562 in 2019; 229,263 in 2020 and 111,400 in 2021.
(4) With respect to PubCo I, the profit interest share held by Messrs. Teague, Ordemann and Bacon at December 31, 2017 was approximately 4.5%, 4.5% and 5.2%, respectively.
(5) Mr. Fowler's share of the profits interest in PrivCo I was approximately 15.5% at December 31, 2017.
(6) Mr. Bulawa's and Mr. Secrest's share of the profits interest in PubCo II was approximately 4.4% and 2.8%, respectively, at December 31, 2017.

Phantom unit awards

For a brief description of phantom unit awards, see "Grants of Equity-Based Awards in Fiscal Year 2017" within this Item 11.

Profits interest awards

In February 2016, EPCO Holdings Inc. ("EPCO Holdings"), a privately held affiliate of EPCO, contributed the following Enterprise common units it owned to the Employee Partnerships: (i) 2,723,052 units to PubCo I, (ii) 2,834,198 units to PubCo II and (iii) 1,111,438 units to PrivCo I. 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, including the named executive officers, 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 profits interest awards were not issued under the 2008 Plan.

In general, the Class A limited partner earns a quarterly preferred return equal to $0.39 per unit on the number of Enterprise common units contributed by EPCO Holdings to each Employee Partnership, with any residual cash amount remaining in each Employee Partnership being paid to the applicable Class B limited partners on a quarterly basis as a distribution. Upon liquidation of an Employee Partnership, assets having a then current fair market value equal to the Class A limited partner's capital base in such Employee Partnership will be distributed to the Class A limited partner. Any remaining assets of such Employee Partnership will be distributed to the Class B limited partners of such Employee Partnership as a residual profits interest, which represents the appreciation in value of the Employee Partnership's assets since the date of EPCO Holdings' contribution to it, as described above.

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

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

Vesting of Equity-Based Awards in 2017

The following table presents the vesting of restricted common unit and phantom unit awards to our named executive officers during the year ended December 31, 2017. These amounts are presented on a gross basis and do not reflect any allocation of compensation to affiliates under the ASA.

	Unit Awards	
Named Executive Officer	**Number of Units Acquired on Vesting (#)** (1)	**Value Realized on Vesting ($)** (2)
A. James Teague:		
Restricted common unit awards	36,100	$ 1,038,597
Phantom unit awards	105,925	3,051,487
W. Randall Fowler:		
Restricted common unit awards	25,000	719,250
Phantom unit awards	73,738	2,124,566
Bryan F. Bulawa:		
Restricted common unit awards	8,124	233,727
Phantom unit awards	25,074	722,454
William Ordemann:		
Restricted common unit awards	10,000	287,700
Phantom unit awards	35,375	1,016,228
Graham W. Bacon:		
Restricted common unit awards	7,750	222,968
Phantom unit awards	31,750	915,073
Brent B. Secrest:		
Restricted common unit awards	3,500	100,695
Phantom unit awards	8,875	255,646

(1) Represents the gross number of common units acquired upon vesting of restricted common unit and phantom unit awards, as applicable, before adjustments for associated tax withholdings.

(2) Amount determined by multiplying the gross number of restricted common unit and phantom unit awards, as applicable, that vested during 2017 by the closing price of our common units on the date of vesting.

Potential Payments Upon Termination or Change-in-Control

None of the named executive officers have any employment agreements that call for the payment of termination or severance benefits or provide for any payments in the event of a change in control of our general partner.

The vesting of profits interest awards under the Employee Partnerships is subject to acceleration upon a change of control (as defined below). In addition, vesting of equity-based awards under EPCO's long-term incentive plans is subject to acceleration upon a qualifying termination, including termination after a change of control of our general partner. Qualifying termination under such awards generally means a termination as an employee of EPCO or an affiliated group member (i) upon death, (ii) a qualifying long-term disability, (iii) a qualifying retirement, or (iv) within one year after a change of control (as defined), other than a termination for cause (as defined) or termination by such person that is not a qualifying termination for good reason (as defined).

A "change of control" under these awards is generally defined to mean that the descendants, heirs and/or legatees of Dan L. Duncan, and/or trusts (including, without limitation, one or more voting trusts) established for their benefit, collectively, cease, directly or indirectly, to control our general partner. Mr. Duncan passed away in March 2010.

Compensation Committee Report

We do not have a separate compensation committee. In addition, we do not directly employ or compensate our named executive officers. Rather, under the ASA, we reimburse EPCO for the compensation of our executive officers. As described in Compensation Discussion and Analysis, decisions regarding the compensation of our named executive officers are made, as applicable, by EPCO, our CEO, our President, and the Audit and Conflicts Committee of our general partner.

In light of the foregoing, the Board has reviewed and discussed with management the Compensation Discussion and Analysis set forth above and determined that it be included in this annual report for the year ended December 31, 2017.

Submitted by: Randa Duncan Williams
Richard H. Bachmann
A. James Teague
W. Randall Fowler
Carin M. Barth
James T. Hackett
Charles E. McMahen
William C. Montgomery
Richard S. Snell
Harry P. Weitzel

Notwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the Securities Exchange Act, as amended, that incorporate future filings, including this annual report, in whole or in part, the foregoing Compensation Committee Report shall not be incorporated by reference into any such filings.

Compensation Committee Interlocks and Insider Participation

None of the directors or executive officers of our general partner served as members of the compensation committee of another entity that has or had an executive officer who served as a member of our Board during the year ended December 31, 2017. As previously noted, we do not have a separate compensation committee. As described in Compensation Discussion and Analysis, decisions regarding the compensation of our named executive officers are made, as applicable, by the Audit and Conflicts Committee of our general partner, our CEO, our President, and EPCO.

Pay Ratio Disclosure

In August 2015 pursuant to a mandate of the Dodd-Frank Wall Street Reform and Consumer Protection Act, the SEC adopted a rule requiring annual disclosure of the ratio of (i) the median of the total annual compensation of all employees of a registrant to (ii) the total annual compensation of the registrant's principal executive officer. Our principal executive officer is Mr. Teague (who serves as CEO of our general partner). The following table summarizes the information used to derive the required pay ratio for the year ended December 31, 2017:

Median total annual compensation	$	106,380
Total annual compensation of Mr. Teague (CEO)	$	7,697,938
Ratio of CEO compensation to median compensation		72 : 1

The median total annual compensation was determined as follows:

- First, a list was prepared of all active EPCO employees, excluding Mr. Teague and those on long-term disability, that devote all or a substantial portion of their time to our consolidated businesses and affairs. This list was based on employee information as of December 31, 2017. There are approximately 7,000 EPCO personnel who spend all or a substantial portion of their time engaged in our business.

- Second, basic wage data for each employee was extracted from Form W-2 information provided to the Internal Revenue Service for calendar year 2017. This information was then sorted and the employee who earned the median compensation (the "median employee") was selected from the list.

- Third, once the median employee was selected, his or her total annual compensation for 2017 was determined using the same method used to determine Mr. Teague's total annual compensation for 2017 as presented in the Summary Compensation Table within this Item 11.

Director Compensation

Neither we nor our general partner provide additional compensation to employees of EPCO for their services as directors of our general partner. For calendar year 2017, the independent voting directors of our general partner were compensated as follows:

- each received an $85,000 annual cash retainer and an annual grant of our common units having a fair market value, based on the closing price of such security on the trading day immediately preceding the date of grant, of approximately $85,000;

- if the individual served as a chairman of the Audit and Conflicts Committee, then he received an additional $20,000 annual cash retainer;

- if the individual served as a chairman of the Governance Committee, then he received an additional $15,000 annual cash retainer; and,

- for those independent voting directors that serve on the Capital Projects Committee, a $2,500 per meeting cash fee for attendance at meetings of this committee.

Our advisory directors, Messrs. Casey and Smith, each received a $150,000 annual cash retainer in 2017. As an honorary director, O.S. Andras received a $20,000 annual cash retainer.

The director compensation program for calendar year 2018 is expected to be the same as 2017.

We bear all costs attributable to the compensation of directors of our general partner. The following table summarizes compensation paid to the non-employee directors of our general partner in 2017:

Non-Employee Director	Fees Earned or Paid in Cash ($)	Value of Equity-Based Awards ($)	Total ($)
Carin M. Barth	$ 87,500	$ 85,000	$ 172,500
Larry J. Casey (1)	150,000	--	150,000
James T. Hackett (2)	105,000	85,000	190,000
Charles E. McMahen (3)	105,000	85,000	190,000
William C. Montgomery	85,000	85,000	170,000
Edwin E. Smith (1)	150,000	--	150,000
Richard S. Snell	90,000	85,000	175,000
O.S. Andras (4)	20,000	--	20,000

(1) Messrs. Casey and Smith serve as advisory directors.
(2) Mr. Hackett serves as chairman of the Governance Committee.
(3) Mr. McMahen serves as chairman of the Audit and Conflicts Committee.
(4) Mr. Andras serves as an honorary director.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.*

Security Ownership of Certain Beneficial Owners

The following table sets forth certain information as of February 15, 2018, regarding each person known by Enterprise GP to beneficially own more than 5% of our limited partner units:

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common units	Randa Duncan Williams (1) 1100 Louisiana Street, 10th Floor Houston, Texas 77002	693,530,754	32.0%

(1) For a detailed listing of the ownership amounts that comprise Ms. Duncan Williams' total beneficial ownership of our common units, see the table presented in the following section, "Security Ownership of Management," within this Item 12.

Ms. Duncan Williams is a DD LLC Trustee and an EPCO Trustee. Ms. Duncan Williams is also currently Chairman and a director of EPCO and Chairman of the Board and a director of our general partner. Ms. Duncan Williams disclaims beneficial ownership of the limited partner units beneficially owned by the EPCO Trustees and the DD LLC Trustees, except to the extent of her voting and dispositive interests in such units.

Security Ownership of Management

The following tables set forth certain information regarding the beneficial ownership of our common units, as of February 15, 2018 by (i) our named executive officers for 2017; (ii) the current directors of Enterprise GP; and (iii) the current directors and executive officers (including named executive officers) of Enterprise GP as a group. All beneficial ownership information has been furnished by the respective directors and executive officers. Each person has sole voting and dispositive power over the securities shown unless indicated otherwise.

	Positions with Enterprise GP at February 15, 2018	**Amount and Nature Of Beneficial Ownership**	**Percent of Class**
Randa Duncan Williams:	Director and Chairman of the Board		
Units controlled by DD LLC Voting Trust:			
Through DFI GP Holdings L.P.		81,688,412	3.8%
Through Dan Duncan LLC		41,762	*
Units controlled by EPCO Voting Trust:			
Through EPCO		26,408,549	1.2%
Through EPCO Investments L.P.		8,346,154	*
Through EPCO Holdings, Inc.		555,444,663	25.6%
Through Employee Partnerships		6,773,688	*
Units controlled by Alkek and Williams, Ltd.		370,928	*
Units controlled by Chaswil, Ltd.		10,000	*
Units controlled by family trusts (1)		14,433,468	*
Units owned personally (2)		13,130	*
Total for Randa Duncan Williams		693,530,754	32.0%

** Represents a beneficial ownership of less than 1% of class*

(1) The number of common units presented for Ms. Duncan Williams includes common units held by family trusts for which she serves as a director of an entity trustee but has disclaimed beneficial ownership (except to the extent of her pecuniary interest therein.

(2) The number of common units presented for Ms. Duncan Williams includes 9,090 common units held by her spouse and 4,040 common units held jointly with her spouse.

EPCO and its privately held affiliates have pledged 81,346,154 of our common units that they own as security under their credit facilities. These credit facilities include customary provisions regarding potential events of default. As a result, a change in ownership of these units could result if an event of default ultimately occurred.

	Positions with Enterprise GP at February 15, 2018	**Amount and Nature Of Beneficial Ownership**	**Percent of Class**
Richard H. Bachmann (1)	Director and Vice Chairman of the Board	1,432,081	*
A. James Teague (2,3)	Director and CEO	1,716,546	*
W. Randall Fowler (2,4)	Director and President	1,440,289	*
Carin M. Barth	Director	31,335	*
James T. Hackett (5)	Director	294,493	*
Charles E. McMahen	Director	107,889	*
William C. Montgomery	Director	46,835	*
Richard S. Snell (6)	Director	63,186	*
Harry P. Weitzel (7)	Director and Senior Vice President, General Counsel and Secretary	44,843	*
William Ordemann (2,8)	Executive Vice President	977,764	*
Graham W. Bacon (2,9)	Executive Vice President	219,775	*
Bryan F. Bulawa (2,10)	Senior Vice President and CFO	177,355	*
Brent B. Secrest (2,11)	Senior Vice President	52,500	*
All directors and executive officers (including all named executive officers) of Enterprise GP, as a group (16 individuals in total) (12)		700,283,084	32.3%

** Represents a beneficial ownership of less than 1% of class*

(1) The number of common units presented for Mr. Bachmann includes 9,588 common units held by his spouse. In addition, the number of common units presented for Mr. Bachmann includes an aggregate 130,000 phantom units that vested in late February 2018, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.
(2) These individuals are named executive officers for the year ended December 31, 2017.
(3) The number of common units presented for Mr. Teague includes (i) 53,000 common units held by a trust and (ii) 11,300 common units held by his spouse. In addition, the number of common units presented for Mr. Teague includes an aggregate 140,925 phantom units that vested in late February 2018, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.
(4) The number of common units presented for Mr. Fowler includes 500,000 common units held by a family limited partnership (for which he has disclaimed beneficial ownership except to the extent of his pecuniary interest). In addition, the number of common units presented for Mr. Fowler includes an aggregate 101,738 phantom units that vested in late February 2018, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.
(5) The number of common units presented for Mr. Hackett includes (i) 9,661 common units held by family trusts and (ii) 58,000 common units held by family limited partnerships.
(6) The number of common units presented for Mr. Snell includes 2,956 common units held by his spouse.
(7) The number of common units presented for Mr. Weitzel includes an aggregate 14,750 phantom units that vested in late February 2018, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.
(8) The number of common units presented for Mr. Ordemann includes an aggregate 48,250 phantom units that vested in late February 2018, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.
(9) The number of common units presented for Mr. Bacon includes an aggregate 46,250 phantom units that vested in late February 2018, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.
(10) The number of common units presented for Mr. Bulawa includes an aggregate 34,475 phantom units that vested in late February 2018, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.
(11) The number of common units presented for Mr. Secrest includes an aggregate 18,875 phantom units that vested in late February 2018, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.
(12) Cumulatively, this group's beneficial ownership amount includes an aggregate 564,243 phantom units that vested in late February 2018, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.

Equity Ownership Guidelines

In order to further align the interests and actions of our general partner's directors and executive officers with our long-term interests and those of our general partner and other unitholders, the Board has adopted and approved certain equity ownership guidelines for our general partner's directors and executive officers. Under these guidelines:

- each non-management director of our general partner is required to own Enterprise common units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such non-management director's aggregate annual cash retainer for service on the Board for the most recently completed calendar year; and

- each executive officer of our general partner is required to own Enterprise common units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such executive officer's aggregate annual base salary for the most recently completed calendar year.

Securities Authorized for Issuance Under Equity Compensation Plans

Currently, the 2008 Plan is EPCO's only long-term incentive plan under which our common units have been authorized for issuance. The 2008 Plan provides for awards of our common units and other rights to our non-management directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the 2008 Plan may be granted in the form of unit options, restricted common units, phantom units, UARs, DERs, unit awards and other unit-based awards or substitute awards. The following table sets forth certain information regarding the 2008 Plan as of January 1, 2018.

Plan Category	Number of Units to Be Issued Upon Exercise of Outstanding Common Unit Options	Weighted-Average Exercise Price of Outstanding Common Unit Options	Number of Units Remaining Available For Future Issuance Under Equity Compensation Plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by unitholders:			
2008 Plan (1)	--	--	24,091,065
Equity compensation plans not approved by unitholders:			
None	--	--	--
Total for equity compensation plans	--	--	24,091,065

(1) At December 31, 2017, the total number of common units authorized for issuance under the 2008 Plan was 40,000,000 common units. This amount increased by 5,000,000 common units on January 1, 2018 and will increase by an additional 5,000,000 common units subsequently on each January 1 thereafter during the term of the 2008 Plan; provided, however, that in no event shall the maximum aggregate amount available for issuance under the 2008 Plan exceed 70,000,000 common units.

Item 13. *Certain Relationships and Related Transactions, and Director Independence.*

Certain Relationships and Related Transactions

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.

Additional information regarding our related party transactions is set forth in Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report and is incorporated by reference into this Item 13.

Review and Approval of Transactions with Related Parties

We consider transactions between us and our subsidiaries and unconsolidated affiliates, on the one hand, and our executive officers and directors (or their immediate family members), our general partner or its affiliates (including other companies owned or controlled by the DD LLC Trustees or the EPCO Trustees), on the other hand, to be related party transactions. As further described below, our partnership agreement sets forth general procedures by which related party transactions and conflicts of interest may be approved or resolved by Enterprise GP or its Audit and Conflicts Committee. In addition, the Audit and Conflicts Committee charter, Enterprise GP's written internal review and approval policies and procedures (referred to as its "management authorization policy") and the amended and restated ASA with EPCO address specific types of related party transactions, as further described below.

Our Audit and Conflicts Committee is comprised of three independent directors: Charles E. McMahen, William C. Montgomery and Richard S. Snell. In accordance with its charter, the Audit and Conflicts Committee reviews and approves related party transactions:

- pursuant to our partnership agreement or the limited liability company agreement of Enterprise GP, as such agreements may be amended from time to time;
- in which an officer or director of Enterprise GP or any of our subsidiaries, or an immediate family member of such an officer or director, has a material financial interest or is otherwise a party;
- when requested to do so by management or the Board;
- with a value of $5 million or more (unless such transaction is equivalent to an arm's length or third party transaction); or
- that it may otherwise deem appropriate from time to time.

The Audit and Conflicts Committee did not review or approve any related party transactions during the year ended December 31, 2017.

Enterprise GP's management authorization policy generally requires Board approval for asset purchase or sales transactions and capital expenditures to the extent such transactions have a value in excess of $250 million. Any such transaction would typically also require Audit and Conflicts Committee review under its charter if such transaction is also a related party transaction.

As noted previously, all of our management, administrative and operating functions are performed by employees of EPCO (pursuant to an administrative services agreement, or ASA) or by other service providers. The ASA governs numerous day-to-day transactions between us, Enterprise GP and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our reimbursement to EPCO of costs, without markup or discount, for those services. The ASA was reviewed, approved and recommended to the Board by our Audit and Conflicts Committee, and the Board also approved it upon receiving such recommendation.

Related party transactions that are outside the scope of the ASA and not reviewed by the Audit and Conflicts Committee are subject to Enterprise GP's management authorization policy. This policy, which applies to related party transactions as well as transactions with third parties, specifies thresholds for our general partner's officers and Board to authorize various categories of transactions, including purchases and sales of assets, commercial and financial transactions and legal agreements.

Partnership Agreement Standards for Audit and Conflicts Committee Review

Under our partnership agreement, whenever a potential conflict of interest exists or arises between Enterprise GP or any of its affiliates, on the one hand, and us, any of our subsidiaries or any partner, on the other hand, any resolution or course of action by Enterprise GP or its affiliates in respect of such conflict of interest is permitted and deemed approved by our limited partners, and will not constitute a breach of our partnership agreement or any agreement contemplated by such agreement, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the partnership agreement is deemed to be, fair and reasonable to us; provided that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by a majority of the members of the Audit and Conflicts Committee (i.e., a "Special Approval" is granted) or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from third parties.

The Audit and Conflicts Committee (in connection with its Special Approval process) may consider the following when resolving conflicts of interest:

- the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;
- the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us);
- any customary or accepted industry practices and any customary or historical dealings with a particular party;
- any applicable generally accepted accounting or engineering practices or principles;
- the relative cost of capital of the parties involved and the consequent rates of return to the equity holders of such parties; and
- such additional factors as the Audit and Conflicts Committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

The level of review and work performed by the Audit and Conflicts Committee with respect to a given transaction varies depending upon the nature of the transaction and the scope of the Audit and Conflicts Committee's obligation. Examples of functions the Audit and Conflicts Committee may, as it deems appropriate, perform in the course of reviewing a transaction include, but are not limited to:

- assessing the business rationale for the transaction;
- reviewing the terms and conditions of the proposed transaction, including consideration and financing requirements, if any;
- assessing the effect of the transaction on our results of operations, financial condition, cash available for distribution, properties or prospects;
- conducting due diligence, including interviews and discussions with management and other representatives and reviewing transaction materials and findings of management and other representatives;
- considering the relative advantages and disadvantages of the transactions to the parties involved;

- engaging third party financial advisors to provide financial advice and assistance, including fairness opinions if requested;
- engaging legal advisors; and
- evaluating and negotiating the transaction and recommending for approval or approving the transaction, as the case may be.

Nothing contained in our partnership agreement requires the Audit and Conflicts Committee to consider the interests of any party other than us. In the absence of the Audit and Conflicts Committee or our general partner acting in bad faith, the resolution, action or terms so made, taken or provided (including granting Special Approval) by the Audit and Conflicts Committee or our general partner with respect to such matter are deemed conclusive and binding on all persons (including all of our limited partners) and do not constitute a breach of partnership agreement, or any other agreement contemplated thereby, or a breach of any standard of care or duty imposed in our partnership agreement or under the Delaware Revised Uniform Limited Partnership Act or any other law, rule or regulation. Our partnership agreement provides that it is presumed that the resolution, action or terms made, taken or provided by the Audit and Conflicts Committee or our general partner were not made, taken or provided in bad faith, and in any proceeding brought by any limited partner or by or on behalf of such limited partner or any other limited partner or us challenging such resolution, action or terms, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Director Independence

Each of the current members of the Audit and Conflicts Committee, namely Messrs. McMahen, Montgomery and Snell, and two members of the Governance Committee, namely Ms. Barth and Mr. Hackett, have been determined to be independent under the applicable NYSE listing standards and rules of the SEC. For a discussion of independence standards applicable to our Board and factors considered by our Board in making its independence determinations, please refer to "Partnership Governance" included under Part III, Item 10 of this annual report.

Other Matters

An immediate family member of Mr. Teague is an employee of EPCO that performs services on our behalf. This individual does not serve as an executive officer of Enterprise GP, EPCO or any of their respective affiliates, and his compensation and other terms of employment are determined on a basis consistent with EPCO's human resources policies. This individual earned total compensation from EPCO of approximately $500 thousand for 2017.

An immediate family member of Ms. Duncan Williams is an employee of EPCO that performs services on our behalf. This individual does not serve as an executive officer of Enterprise GP, EPCO or any of their respective affiliates, and his compensation and other terms of employment are determined on a basis consistent with EPCO's human resources policies. This individual earned total compensation from EPCO of approximately $125 thousand for 2017.

Item 14. *Principal Accountant Fees and Services.*

With the approval of the Audit and Conflicts Committee of our general partner, we have engaged Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte & Touche") as our independent registered public accounting firm and principal accountants. The following table summarizes amounts billed to us by Deloitte & Touche for (or in) each of the years presented, as applicable:

	For the Year Ended December 31,	
	2017 (1)	**2016** (2)
Audit fees	$ 5,047,700	$ 4,881,250

(1) Audit fees for 2017 include $135,000 of charges for audit-related projects that were reimbursed by joint venture partners.
(2) Audit fees for 2016 include $225,000 of charges for audit-related projects that were reimbursed by joint venture partners.

As presented in the preceding table, "Audit Fees" typically represent amounts billed for each year in connection with (i) the annual audit of our consolidated financial statements and internal controls over financial reporting, (ii) the quarterly review of our consolidated financial statements filed on Form 10-Q, (iii) standalone annual audits of our consolidated subsidiaries and (iv) those services normally provided by Deloitte & Touche in connection with our statutory and regulatory filings or engagements, including comfort letters, consents and other services related to SEC matters. We did not engage Deloitte & Touche to perform any other services for us during the last two years.

In connection with its oversight responsibilities, the Audit and Conflicts Committee has adopted a pre-approval policy regarding any services to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other. When Deloitte & Touche's services are required, management and Deloitte & Touche discuss the proposed work with the Audit and Conflicts Committee. These discussions typically address the reasons for the project, the scope of the work to be performed and an estimate of the fee to be charged by Deloitte & Touche for such work. The Audit and Conflicts Committee discusses the request with management and Deloitte & Touche and, if the work is deemed necessary and appropriate for Deloitte & Touche to perform, approves the request subject to the fee estimate presented (the initial "pre-approved" fee amount). If at a later date, it appears that the initial pre-approved fee amount is insufficient to complete the work, management and Deloitte & Touche must present a supplemental request to the Audit and Conflicts Committee to increase the approved amount along with reasons for the increase. Under the pre-approval policy, management cannot act upon its own to authorize an expenditure for Deloitte & Touche services outside of the pre-approved amounts. On a quarterly basis, the Audit and Conflicts Committee is provided a schedule that compares the pre-approved amounts for each primary service category with the actual fees billed for each type of service. We believe the Audit and Conflicts Committee's pre-approval process helps to ensure the independence of our principal accountant from management.

We are prohibited from using Deloitte & Touche to perform general bookkeeping, human resources or management functions for us, and any other service not permitted by the PCAOB.

PART IV

Item 15. *Exhibits and Financial Statement Schedules.*

(a) The following documents are filed as a part of this annual report:

(1) Financial Statements: See "Index to Consolidated Financial Statements" beginning on page F-1 of this annual report for the financial statements included herein.

(2) Financial Statement Schedules: The separate filing of financial statement schedules has been omitted because such schedules are either not applicable or the information called for therein appears in the footnotes of our Consolidated Financial Statements.

(3) Exhibits:

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

2.10	Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010).
2.11	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
2.12	Contribution and Purchase Agreement, dated as of October 1, 2014, by and among Enterprise Products Partners L.P., Oiltanking Holding Americas, Inc. and OTB Holdco, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2014).
2.13	Agreement and Plan of Merger, dated as of November 11, 2014, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPOT MergerCo LLC, Oiltanking Partners, L.P. and OTLP GP, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed November 12, 2014).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.6 to Form 8-K filed November 23, 2010).
3.3	Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated November 22, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K filed November 23, 2010).
3.4	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 11, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 16, 2011).
3.5	Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 21, 2014 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 26, 2014).
3.6	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	Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.9	Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed May 24, 2007).
4.10	Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.11	Eleventh Supplemental Indenture, dated as of September 4, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed September 5, 2007).
4.12	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.13	Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.14	Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.15	Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells

	Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.16	Nineteenth Supplemental Indenture, dated as of May 20, 2010, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.17	Twentieth Supplemental Indenture, dated as of January 13, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.18	Twenty-First Supplemental Indenture, dated as of August 24, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.19	Twenty-Second Supplemental Indenture, dated as of February 15, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
4.20	Twenty-Third Supplemental Indenture, dated as of August 13, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 13, 2012).
4.21	Twenty-Fourth Supplemental Indenture, dated as of March 18, 2013, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.22	Twenty-Fifth Supplemental Indenture, dated as of February 12, 2014, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.23	Twenty-Sixth Supplemental Indenture, dated as of October 14, 2014, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.24	Twenty-Seventh Supplemental Indenture, dated as of May 7, 2015, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.25	Twenty-Eighth Supplemental Indenture, dated as of April 13, 2016, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 13, 2016).
4.26	Twenty-Ninth Supplemental Indenture, dated as of August 16, 2017, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 16, 2017).
4.27	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 $300.0 million principal amount of Junior Subordinated Notes due 2066 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.33	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).
10.1***	Enterprise Products 1998 Long-Term Incentive Plan (Amended and Restated as of February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 26, 2010).
10.2***	Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 10-Q filed August 9, 2010).
10.3***	2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) (incorporated by reference to Annex A to Definitive Proxy Statement filed August 26, 2013).
10.4***	Form of Employee Phantom Unit Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 10-K filed February 24, 2017).
10.5	Distribution Waiver Agreement, dated as of November 22, 2010, by and among Enterprise Products Partners L.P., EPCO Holdings, Inc. and the EPD Unitholder named therein (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 23, 2010).

10.6	Eighth Amended and Restated Administrative Services Agreement, effective as of February 13, 2015, by and among Enterprise Products Company, EPCO Holdings, Inc., Enterprise Products Holdings LLC, Enterprise Products Partners L.P., Enterprise Products OLPGP, Inc., Enterprise Products Operating LLC and the Oiltanking Parties named therein (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 13, 2015).
10.7	364-Day Revolving Credit Agreement, dated as of September 13, 2017, among Enterprise Products Operating LLC, the Lenders party thereto, Citibank, N.A. as Administrative Agent, Wells Fargo Bank, National Association, DNB Bank ASA, New York Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, Ltd. and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Syndication Agents, and Barclays Bank PLC, Royal Bank of Canada, Sumitomo Mitsui Banking Corporation, SunTrust Bank, The Bank of Nova Scotia and The Toronto-Dominion Bank, New York Branch, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 15, 2017).
10.8	Guaranty Agreement, dated as of September 13, 2017, by Enterprise Products Partners L.P. in favor of Citibank, N.A., as administrative agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed September 15, 2017).
10.9	Revolving Credit Agreement, dated as of September 13, 2017, among Enterprise Products Operating LLC, the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent, Citibank, N.A., DNB Bank ASA, New York Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, Ltd. and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Syndication Agents, and Barclays Bank PLC, Royal Bank of Canada, Sumitomo Mitsui Banking Corporation, SunTrust Bank, The Bank of Nova Scotia and The Toronto-Dominion Bank, New York Branch, as Co-Documentation Agents (incorporated by reference to Exhibit 10.3 to Form 8-K filed September 15, 2017).
10.10	Guaranty Agreement, dated as of September 13, 2017, by Enterprise Products Partners L.P. in favor of Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.4 to Form 8-K filed September 15, 2017).
10.11	Liquidity Option Agreement, dated as of October 1, 2014, between Enterprise Products Partners, L.P., Oiltanking Holding Americas, Inc., and Marquard & Bahls AG (incorporated by reference to Exhibit 10.3 to Form 8-K filed October 1, 2014).
10.12	Support Agreement, dated as of November 11, 2014, by and among Enterprise Products Partners L.P., Enterprise Products Operating LLC and Oiltanking Partners, L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 12, 2014).
10.13***	EPD PubCo Unit I L.P. Amended and Restated Agreement of Limited Partnership dated November 3, 2016 (incorporated by reference to Exhibit 10.17 to Form 10-K filed February 24, 2017).
10.14***	EPD PubCo Unit II L.P. Amended and Restated Agreement of Limited Partnership dated November 3, 2016 (incorporated by reference to Exhibit 10.18 to Form 10-K filed February 24, 2017).
10.15***	EPD PrivCo Unit I L.P. Amended and Restated Agreement of Limited Partnership dated November 3, 2016 (incorporated by reference to Exhibit 10.19 to Form 10-K filed February 24, 2017).
10.16***	EPD PubCo Unit III L.P. Amended and Restated Agreement of Limited Partnership dated November 3, 2016 (incorporated by reference to Exhibit 10.20 to Form 10-K filed February 24, 2017).
10.17	Equity Distribution Agreement, dated December 1, 2017, by and among Enterprise Products Partners L.P., Enterprise Products OLPGP, Inc., Enterprise Products Operating LLC and Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., DNB Markets, Inc., Jefferies LLC, J.P. Morgan Securities LLC, Mizuho Securities USA Inc., Morgan Stanley & Co. LLC, MUFG Securities Americas Inc., Raymond James & Associates, Inc., RBC Capital Markets, LLC, Scotia Capital (USA) Inc., SG Americas Securities, LLC, SMBC Nikko Securities America, Inc., SunTrust Robinson Humphrey, Inc., TD Securities (USA) LLC, UBS Securities LLC, USCA Securities LLC and Wells Fargo Securities, LLC. (incorporated by reference to Exhibit 1.1 to Form 8-K filed December 1, 2017).

12.1#	Computation of ratio of earnings to fixed charges for each of the years ended December 31, 2017, 2016, 2015, 2014 and 2013.
21.1#	List of consolidated subsidiaries as of February 1, 2018.
23.1#	Consent of Deloitte & Touche LLP.
31.1#	Sarbanes-Oxley Section 302 certification of A. James Teague for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2017.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2017.
31.3#	Sarbanes-Oxley Section 302 certification of Bryan F. Bulawa for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2017.
32.1#	Sarbanes-Oxley Section 906 certification of A. James Teague for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2017.
32.2#	Sarbanes-Oxley Section 906 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2017.
32.3#	Sarbanes-Oxley Section 906 certification of Bryan F. Bulawa for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2017.
101.CAL#	XBRL Calculation Linkbase Document
101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
101.LAB#	XBRL Labels Linkbase Document
101.PRE#	XBRL Presentation Linkbase Document
101.SCH#	XBRL Schema Document

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

Item 16. *Form 10-K Summary.*

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 February 28, 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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on February 28, 2018.

Signature	**Title (Position with Enterprise Products Holdings LLC)**
/s/ Randa Duncan Williams Randa Duncan Williams	Director and Chairman of the Board
/s/ Richard H. Bachmann Richard H. Bachmann	Director and Vice-Chairman of the Board
/s/ A. James Teague A. James Teague	Director and Chief Executive Officer
/s/ W. Randall Fowler W. Randall Fowler	Director and President
/s/ Bryan F. Bulawa Bryan F. Bulawa	Senior Vice President and Chief Financial Officer
/s/ Harry P. Weitzel Harry P. Weitzel	Director and Senior Vice President, General Counsel and Secretary
/s/ Carin M. Barth Carin M. Barth	Director
/s/ James T. Hackett James T. Hackett	Director
/s/ Charles E. McMahen Charles E. McMahen	Director
/s/ William C. Montgomery William C. Montgomery	Director
/s/ Richard S. Snell Richard S. Snell	Director
/s/ R. Daniel Boss R. Daniel Boss	Senior Vice President (Accounting and Risk Control)
/s/ Michael W. Hanson Michael W. Hanson	Vice President and Principal Accounting Officer

Item 8. Financial Statements and Supplementary Data.

ENTERPRISE PRODUCTS PARTNERS L.P.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products Holdings LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related statements of consolidated operations, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2018

We have served as the Company's auditor since 1997.

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

	December 31, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5.1	$ 63.1
Restricted cash	65.2	354.5
Accounts receivable – trade, net of allowance for doubtful accounts of $12.1 at December 31, 2017 and $11.3 at December 31, 2016	4,358.4	3,329.5
Accounts receivable – related parties	1.8	1.1
Inventories	1,609.8	1,770.5
Derivative assets (see Note 14)	153.4	541.4
Prepaid and other current assets	312.7	468.1
Total current assets	6,506.4	6,528.2
Property, plant and equipment, net	35,620.4	33,292.5
Investments in unconsolidated affiliates	2,659.4	2,677.3
Intangible assets, net of accumulated amortization of $1,564.8 at December 31, 2017 and $1,403.1 at December 31, 2016 (see Note 7)	3,690.3	3,864.1
Goodwill (see Note 7)	5,745.2	5,745.2
Other assets	196.4	86.7
Total assets	$ 54,418.1	$ 52,194.0
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 8)	$ 2,855.0	$ 2,576.8
Accounts payable – trade	801.7	397.7
Accounts payable – related parties	127.3	105.1
Accrued product payables	4,566.3	3,613.7
Accrued interest	358.0	340.8
Derivative liabilities (see Note 14)	168.2	737.7
Other current liabilities	418.6	478.7
Total current liabilities	9,295.1	8,250.5
Long-term debt (see Note 8)	21,713.7	21,120.9
Deferred tax liabilities	58.5	52.7
Other long-term liabilities	578.4	503.9
Commitments and contingencies (see Note 17)		
Equity: (see Note 9)		
Partners' equity:		
Limited partners:		
Common units (2,161,089,479 units outstanding at December 31, 2017 and 2,117,588,414 units outstanding at December 31, 2016)	22,718.9	22,327.0
Accumulated other comprehensive loss	(171.7)	(280.0)
Total partners' equity	22,547.2	22,047.0
Noncontrolling interests	225.2	219.0
Total equity	22,772.4	22,266.0
Total liabilities and equity	$ 54,418.1	$ 52,194.0

See Notes to Consolidated Financial Statements.

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

	For the Year Ended December 31,		
	2017	**2016**	**2015**
Revenues:			
Third parties	$ 29,196.5	$ 22,965.6	$ 26,955.6
Related parties	45.0	56.7	72.3
Total revenues (see Note 10)	29,241.5	23,022.3	27,027.9
Costs and expenses:			
Operating costs and expenses:			
Third parties	24,444.7	18,539.5	22,588.2
Related parties	1,112.8	1,104.0	1,080.5
Total operating costs and expenses	25,557.5	19,643.5	23,668.7
General and administrative costs:			
Third parties	59.6	47.0	78.5
Related parties	121.5	113.1	114.1
Total general and administrative costs	181.1	160.1	192.6
Total costs and expenses (see Note 10)	25,738.6	19,803.6	23,861.3
Equity in income of unconsolidated affiliates	426.0	362.0	373.6
Operating income	3,928.9	3,580.7	3,540.2
Other income (expense):			
Interest expense	(984.6)	(982.6)	(961.8)
Change in fair market value of Liquidity Option Agreement (see Note 17)	(64.3)	(24.5)	(25.4)
Other, net	1.3	2.8	2.9
Total other expense, net	(1,047.6)	(1,004.3)	(984.3)
Income before income taxes	2,881.3	2,576.4	2,555.9
Benefit from (provision for) income taxes (see Note 16)	(25.7)	(23.4)	2.5
Net income	2,855.6	2,553.0	2,558.4
Net income attributable to noncontrolling interests (see Note 9)	(56.3)	(39.9)	(37.2)
Net income attributable to limited partners	$ 2,799.3	$ 2,513.1	$ 2,521.2
Earnings per unit: (see Note 11)			
Basic earnings per unit	$ 1.30	$ 1.20	$ 1.28
Diluted earnings per unit	$ 1.30	$ 1.20	$ 1.26

See Notes to Consolidated Financial Statements.

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

	For the Year Ended December 31,		
	2017	**2016**	**2015**
Net income	$ 2,855.6	$ 2,553.0	$ 2,558.4
Other comprehensive income (loss):			
Cash flow hedges:			
Commodity derivative instruments:			
Changes in fair value of cash flow hedges	(38.5)	(193.8)	214.9
Reclassification of losses (gains) to net income	112.2	53.4	(228.2)
Interest rate derivative instruments:			
Changes in fair value of cash flow hedges	(5.7)	42.3	--
Reclassification of losses to net income	40.4	37.4	35.3
Total cash flow hedges	108.4	(60.7)	22.0
Other	(0.1)	(0.1)	0.4
Total other comprehensive income (loss)	108.3	(60.8)	22.4
Comprehensive income	2,963.9	2,492.2	2,580.8
Comprehensive income attributable to noncontrolling interests	(56.3)	(39.9)	(37.2)
Comprehensive income attributable to limited partners	$ 2,907.6	$ 2,452.3	$ 2,543.6

See Notes to Consolidated Financial Statements.

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

	For the Year Ended December 31,		
	2017	2016	2015
Operating activities:			
Net income	$ 2,855.6	$ 2,553.0	$ 2,558.4
Reconciliation of net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	1,644.0	1,552.0	1,516.0
Asset impairment and related charges	49.8	53.5	162.6
Equity in income of unconsolidated affiliates	(426.0)	(362.0)	(373.6)
Distributions received on earnings from unconsolidated affiliates	433.7	380.5	462.1
Net losses (gains) attributable to asset sales (see Note 19)	(10.7)	(2.5)	15.6
Deferred income tax expense (benefit)	6.1	6.6	(20.6)
Change in fair market value of derivative instruments	22.8	45.0	(18.4)
Change in fair market value of Liquidity Option Agreement	64.3	24.5	25.4
Net effect of changes in operating accounts (see Note 19)	32.2	(180.9)	(323.3)
Other operating activities	(5.5)	(2.9)	(1.8)
Net cash flows provided by operating activities	4,666.3	4,066.8	4,002.4
Investing activities:			
Capital expenditures	(3,147.9)	(3,025.1)	(3,830.7)
Contributions in aid of construction costs	46.1	41.0	19.1
Cash used for business combinations, net of cash received (see Note 12)	(198.7)	(1,000.0)	(1,056.5)
Investments in unconsolidated affiliates	(50.5)	(138.8)	(162.6)
Distributions received for return of capital from unconsolidated affiliates	49.3	71.0	--
Proceeds from asset sales (see Note 19)	40.1	46.5	1,608.6
Other investing activities	(24.5)	(0.4)	(3.8)
Cash used in investing activities	(3,286.1)	(4,005.8)	(3,425.9)
Financing activities:			
Borrowings under debt agreements	69,315.3	62,813.9	21,081.1
Repayments of debt	(68,459.6)	(61,672.6)	(19,867.2)
Debt issuance costs	(24.1)	(10.6)	(24.0)
Monetization of interest rate derivative instruments (see Note 14)	30.6	6.1	--
Cash distributions paid to limited partners (see Note 9)	(3,569.9)	(3,300.5)	(2,943.7)
Cash payments made in connection with distribution equivalent rights	(15.1)	(11.7)	(7.7)
Cash distributions paid to noncontrolling interests (see Note 9)	(49.2)	(47.4)	(48.0)
Cash contributions from noncontrolling interests (see Note 9)	0.4	20.4	54.0
Net cash proceeds from the issuance of common units	1,073.4	2,542.8	1,188.6
Other financing activities	(29.3)	(18.7)	(49.1)
Cash provided by (used in) financing activities	(1,727.5)	321.7	(616.0)
Net change in cash, cash equivalents and restricted cash	(347.3)	382.7	(39.5)
Cash, cash equivalents and restricted cash, January 1	417.6	34.9	74.4
Cash, cash equivalents and restricted cash, December 31	$ 70.3	$ 417.6	$ 34.9

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED EQUITY
(See Note 9 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, 2015	$ 18,304.8	$ (241.6)	$ 1,629.0	$ 19,692.2
Net income	2,521.2	--	37.2	2,558.4
Cash distributions paid to limited partners	(2,943.7)	--	--	(2,943.7)
Cash payments made in connection with distribution equivalent rights	(7.7)	--	--	(7.7)
Cash distributions paid to noncontrolling interests	--	--	(48.0)	(48.0)
Cash contributions from noncontrolling interests	--	--	54.0	54.0
Common units issued and noncontrolling interests acquired in connection with Step 2 of Oiltanking acquisition	1,408.7	--	(1,408.7)	--
Removal of noncontrolling interests in connection with sale of Offshore Business	--	--	(62.1)	(62.1)
Net cash proceeds from the issuance of common units	1,188.6	--	--	1,188.6
Amortization of fair value of equity-based awards	92.4	--	--	92.4
Cash flow hedges	--	22.0	--	22.0
Other	(50.0)	0.4	4.6	(45.0)
Balance, December 31, 2015	20,514.3	(219.2)	206.0	20,501.1
Net income	2,513.1	--	39.9	2,553.0
Cash distributions paid to limited partners	(3,300.5)	--	--	(3,300.5)
Cash payments made in connection with distribution equivalent rights	(11.7)	--	--	(11.7)
Cash distributions paid to noncontrolling interests	--	--	(47.4)	(47.4)
Cash contributions from noncontrolling interests	--	--	20.4	20.4
Net cash proceeds from the issuance of common units	2,542.8	--	--	2,542.8
Amortization of fair value of equity-based awards	90.2	--	--	90.2
Cash flow hedges	--	(60.7)	--	(60.7)
Other	(21.2)	(0.1)	0.1	(21.2)
Balance, December 31, 2016	22,327.0	(280.0)	219.0	22,266.0
Net income	2,799.3	--	56.3	2,855.6
Cash distributions paid to limited partners	(3,569.9)	--	--	(3,569.9)
Cash payments made in connection with distribution equivalent rights	(15.1)	--	--	(15.1)
Cash distributions paid to noncontrolling interests	--	--	(49.2)	(49.2)
Cash contributions from noncontrolling interests	--	--	0.4	0.4
Net cash proceeds from the issuance of common units	1,073.4	--	--	1,073.4
Common units issued in connection with employee compensation	33.7	--	--	33.7
Amortization of fair value of equity-based awards	99.0	--	--	99.0
Cash flow hedges	--	108.4	--	108.4
Other	(28.5)	(0.1)	(1.3)	(29.9)
Balance, December 31, 2017	$ 22,718.9	$ (171.7)	$ 225.2	$ 22,772.4

See Notes to 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 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 December 31, 2017.

References to "EFS Midstream" mean EFS Midstream LLC, which we acquired in July 2015 from affiliates of Pioneer Natural Resources Company ("PXD") and Reliance Industries Limited ("Reliance"). See Note 12 for additional information regarding this acquisition.

References to "Offshore Business" refer to the Gulf of Mexico operations we sold to Genesis Energy, L.P. ("Genesis") in July 2015. See Note 10 for additional information regarding this sale.

References to "Oiltanking" and "Oiltanking GP" mean Oiltanking Partners, L.P. and OTLP GP, LLC, the general partner of Oiltanking, respectively. In October 2014, we acquired approximately 65.9% of the limited partner interests of Oiltanking, all of the member interests of Oiltanking GP and the incentive distribution rights ("IDRs") held by Oiltanking GP from Oiltanking Holding Americas, Inc. ("OTA"), a United States ("U.S.") corporation, as the first step of a two-step acquisition of Oiltanking. In February 2015, we completed the second step of this transaction consisting of the acquisition of the noncontrolling interests in Oiltanking. See Note 12 for additional information regarding this acquisition.

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

Note 1. Partnership Operations, Organization and Basis of Presentation

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

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the U.S., Canada and the Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations currently include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and export and import terminals (including those used to export liquefied petroleum gases, or "LPG," and ethane); crude oil gathering, transportation, storage, and export and import terminals; petrochemical and refined products transportation, storage, export and import terminals, and related services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems. Our assets currently include approximately 50,000 miles of pipelines; 260 million barrels ("MMBbls") of storage capacity for NGLs, crude oil, petrochemicals and refined products; and 14 billion cubic feet ("Bcf") of natural gas storage capacity. All statistical data (e.g., pipeline mileage, processing capacity and similar operating metrics) in these notes to consolidated financial statements are unaudited.

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 the ASA and other related party matters.

Our operations are reported under four business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services and (iv) Petrochemical & Refined Products Services. See Note 10 for additional information regarding our business segments.

Note 2. Summary of Significant Accounting Policies

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts, including those related to natural gas imbalances. Our procedure for estimating the allowance for doubtful accounts is based on: (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research and (iii) the levels of credit we grant to customers. In addition, we may increase the allowance for doubtful accounts in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses.

The following table presents our allowance for doubtful accounts activity for the periods indicated:

	For the Year Ended December 31,		
	2017	2016	2015
Balance at beginning of period	$ 11.3	$ 12.1	$ 13.9
Charged to costs and expenses	2.7	2.3	0.8
Deductions	(1.9)	(3.1)	(2.6)
Balance at end of period	$ 12.1	$ 11.3	$ 12.1

See "Credit Risk" in Note 18 for additional information.

Cash, Cash Equivalents and Restricted Cash

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase.

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.

In November 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash, which standardizes the presentation of transfers to and from restricted cash within the cash flow statement. As a result, the cash flow statement will present changes in total cash amounts, regardless of whether the cash balances are restricted or unrestricted.

We adopted this guidance in the fourth quarter of 2017 and applied this ASU retrospectively to the periods presented in our Statements of Consolidated Cash Flows. As a result, the decrease in restricted cash of $338.6 million and $15.9 million was excluded from net cash used in investing activities for the years ended December 31, 2016 and 2015, respectively.

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

	December 31,	
	2017	2016
Cash and cash equivalents	$ 5.1	$ 63.1
Restricted cash	65.2	354.5
Total cash, cash equivalents and restricted cash shown in the Statements of Consolidated Cash Flows	$ 70.3	$ 417.6

The balance of restricted cash at December 31, 2017 consisted of initial margin requirements of $33.4 million and variation margin requirements of $31.8 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.

Consolidation Policy

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all intercompany accounts and transactions. We also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership. We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own. Third party or affiliate ownership interests in our controlled subsidiaries are presented as noncontrolling interests. See Note 9 for information regarding noncontrolling interests.

If the entity is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50%, unless our interest is so minor that we have virtually no influence over the investee's operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the investee's operating and financial policies. In consolidation, we eliminate our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates to the extent such amounts remain on our Consolidated Balance Sheets (or those of our equity method investments) in inventory or similar accounts.

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

We accrue an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when the likelihood of loss is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material to our consolidated financial statements, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. See Note 17 for additional information regarding our contingencies.

Current Assets and Current Liabilities
We present, as individual captions in our Consolidated Balance Sheets, all components of current assets and current liabilities that exceed 5% of total current assets and current liabilities, respectively.

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

We are required to recognize derivative instruments at fair value as either assets or liabilities on our Consolidated Balance Sheets unless such instruments meet certain normal purchase/normal sale criteria. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of derivative instruments are reported in different ways, depending on the nature and effectiveness of the hedging activities to which they relate. After meeting specified conditions, a qualified derivative may be designated as a total or partial hedge of:

- Changes in the fair value of a recognized asset or liability, or an unrecognized firm commitment – In a fair value hedge, gains and losses for both the derivative instrument and the hedged item are recognized in income during the period of change.

- Variable cash flows of a forecasted transaction – In a cash flow hedge, the effective portion of the hedge is reported in other comprehensive income (loss) and is reclassified into earnings when the forecasted transaction affects earnings.

An effective hedge relationship is one in which the change in fair value of a derivative instrument can be expected to offset 80% to 125% of the changes in fair value of a hedged item at inception and throughout the life of the hedging relationship. The effective portion of a hedge relationship is the amount by which the derivative instrument exactly offsets the change in fair value of the hedged item during the reporting period. Conversely, ineffectiveness represents the change in the fair value of the derivative instrument that does not exactly offset the change in the fair value of the hedged item. Any ineffectiveness associated with a hedge relationship is recognized in earnings immediately. Ineffectiveness can be caused by, among other things, changes in the timing of forecasted transactions or a mismatch of terms between the derivative instrument and the hedged item.

A contract designated as a cash flow hedge of an anticipated transaction that is not probable of occurring is immediately recognized in earnings.

Certain of our derivative instruments do not qualify for hedge accounting treatment; therefore, these instruments are accounted for using mark-to-market accounting.

For certain physical forward commodity derivative contracts, we apply the normal purchase/normal sale exception, whereby changes in the mark-to-market values of such contracts are not recognized in income. As a result, the revenues and expenses associated with such physical transactions are recognized during the period when volumes are physically delivered or received. Physical forward commodity contracts subject to this exception are evaluated for the probability of future delivery and are periodically back-tested once the forecasted period has passed to determine whether similar forward contracts are probable of physical delivery in the future. See Note 14 for additional information regarding our derivative instruments.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2017, none of our estimated environmental remediation liabilities were discounted to present value since the ultimate amount and timing of cash payments for such liabilities were not readily determinable.

The following table presents the activity of our environmental reserves for the periods indicated:

	For the Year Ended December 31,		
	2017	2016	2015
Balance at beginning of period	$ 11.9	$ 13.0	$ 15.6
Charged to costs and expenses	12.1	7.0	6.4
Acquisition-related additions and other	1.7	0.5	1.1
Deductions	(14.1)	(8.6)	(10.1)
Balance at end of period	$ 11.6	$ 11.9	$ 13.0

At December 31, 2017 and 2016, $5.6 million of our environmental reserves were classified as current liabilities.

Estimates

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

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

Fair Value Measurements

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

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

The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

- Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur with sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the New York Mercantile Exchange ("NYMEX")). Our Level 1 fair values consist of financial assets and liabilities such as exchange-traded commodity derivative instruments.

- Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, the time value of money, volatility factors, current market and contractual prices for the underlying instruments and other relevant economic measures. Substantially all of these assumptions (i) are observable in the marketplace throughout the full term of the instrument; (ii) can be derived from observable data; or (iii) are validated by inputs other than quoted prices (e.g., interest rate and yield curves at commonly quoted intervals). Our Level 2 fair values primarily consist of commodity derivative instruments such as forwards, swaps and other instruments transacted on an exchange or over-the-counter and interest rate derivative instruments. The fair values of these derivative instruments are based on observable price quotes for similar products and locations. The fair value of our interest rate derivatives are determined using financial models that incorporate the implied forward LIBOR yield curve for the same period as the future interest rate swap settlements.

- Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect management's ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available to us in the circumstances, which might include our internally developed data. Level 3 inputs are typically used in connection with internally developed valuation methodologies where we make our best estimate of an instrument's fair value. With regards to commodity derivatives, our Level 3 fair values primarily consist of ethane, propane, normal butane and natural gasoline-based contracts with terms greater than one year and certain options used to hedge natural gas storage inventory and transportation capacities. In addition, we often rely on price quotes from reputable brokers who publish price quotes on certain products and compare these prices to other reputable brokers for the same products in the same markets whenever possible. These prices, when combined with data from our commodity derivative instruments, are used in our models to determine the fair value of such instruments.

Transfers within the fair value hierarchy routinely occur for certain term contracts as prices and other inputs used for the valuation of future delivery periods become more observable with the passage of time. Other transfers are made periodically in response to changing market conditions that affect liquidity, price observability and other inputs used in determining valuations. We deem any such transfers to have occurred at the end of the quarter in which they transpired. There were no transfers between Level 1 and 2 during the years ended December 31, 2017 and 2016.

We have a risk management policy that covers our Level 3 commodity derivatives. Governance and oversight of risk management activities for these commodities are provided by our Chief Executive Officer with guidance and support from a risk management committee ("RMC") that meets quarterly (or on a more frequent basis, if needed). Members of executive management attend the RMC meetings, which are chaired by the head of our commodities risk control group. This group is responsible for preparing and distributing daily reports and risk analysis to members of the RMC and other appropriate members of management. These reports include mark-to-market valuations with the one-day and month-to-date changes in fair values. This group also develops and validates the forward commodity price curves used to estimate the fair values of our Level 3 commodity derivatives. These forward curves incorporate published indexes, market quotes and other observable inputs to the extent available.

Impairment Testing for Goodwill

Our goodwill amounts are assessed for impairment on a routine annual basis or when impairment indicators are present. If such indicators occur (e.g., the loss of a significant customer or technological obsolescence of assets), the estimated fair value of the reporting unit to which the goodwill is assigned is determined and compared to its carrying value. If the fair value of the reporting unit is less than its carrying value including associated goodwill amounts, a non-cash impairment charge to earnings is recorded to reduce the carrying value of the goodwill to its implied fair value.

Our reporting unit estimated fair values are based on assumptions regarding the future economic prospects of the businesses that comprise each reporting unit. Such assumptions include: (i) discrete financial forecasts for the assets classified within the reporting unit, which, in turn, rely on management's estimates of operating margins, throughput volumes and similar factors; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates. We believe the assumptions we use in estimating reporting unit fair values are consistent with those that would be employed by market participants in their fair value estimation process. Based on our most recent goodwill impairment test at December 31, 2017, each reporting unit's fair value was substantially in excess of its carrying value (i.e., by at least 10%).

See Note 7 for additional information regarding goodwill.

Impairment Testing for Long-Lived Assets

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset's carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset's carrying value over its estimated fair value is recorded. Fair value is defined as the price that would be received to sell an asset or be paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques. See Note 14 for information regarding non-cash impairment charges related to long-lived assets.

Impairment Testing for Unconsolidated Affiliates
We evaluate our equity method investments for impairment to determine whether there are events or changes in circumstances that indicate there is a loss in value of the investment attributable to an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the entity and/or long-term negative changes in the entity's industry. In the event we determine that the loss in value of an investment is an other than temporary decline, we record a non-cash impairment charge to equity earnings to adjust the carrying value of the investment to its estimated fair value. There were not any non-cash impairment charges related to our equity method investments during the years ended 2017, 2016 and 2015. See Note 6 for information regarding our equity method investments.

Inventories
Inventories primarily consist of NGLs, petrochemicals, refined products, crude oil and natural gas volumes that are valued at the lower of cost or net realizable value. We capitalize, as a cost of inventory, shipping and handling charges (e.g., pipeline transportation and storage fees) and other related costs associated with purchased volumes. As volumes are sold and delivered out of inventory, the cost of these volumes (including freight-in charges that have been capitalized as part of inventory cost) are charged to operating costs and expenses. Shipping and handling fees associated with products we sell and deliver to customers are charged to operating costs and expenses as incurred. See Note 4 for additional information regarding our inventories.

Property, Plant and Equipment
Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized, and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in results of operations for the respective period.

We capitalize interest costs incurred on funds used to construct property, plant and equipment while the asset is in its construction phase. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset's estimated useful life as a component of depreciation expense. When capitalized interest is recorded, it reduces interest expense from what it would be otherwise.

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. With respect to midstream energy assets such as natural gas gathering systems that are reliant upon a specific natural resource basin for throughput volumes, the anticipated useful economic life of such assets may be limited by the estimated life of the associated natural resource basin from which the assets derive benefit. Our forecast of the remaining life for the applicable resource basins is based on several factors, including information published by the U.S. Energy Information Administration. Where appropriate, we use other depreciation methods (generally accelerated) for tax purposes.

Leasehold improvements are recorded as a component of property, plant and equipment. The cost of leasehold improvements is charged to earnings using the straight-line method over the shorter of (i) the remaining lease term or (ii) the estimated useful lives of the improvements. We consider renewal terms that are deemed reasonably assured when estimating remaining lease terms.

Our assumptions regarding the useful economic lives and residual values of our assets may change in response to new facts and circumstances, which would prospectively impact our depreciation expense amounts. Examples of such circumstances include, but are not limited to: (i) changes in laws and regulations that limit the estimated economic life of an asset; (ii) changes in technology that render an asset obsolete; (iii) changes in expected salvage values or (iv) significant changes in the forecast life of the applicable resource basins, if any.

Certain of our plant operations entail periodic planned outages for major maintenance activities. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services and related items. We use the expense-as-incurred method for our planned major maintenance activities for plant operations; however, the cost of annual planned major maintenance projects for such plants are deferred and recognized on a straight-line basis until the next planned annual outage. With regard to the planned major maintenance activities on our marine transportation assets and underground storage caverns, we use the deferral method to account for such costs. Under this method, major maintenance costs are capitalized and amortized over the period until the next major overhaul or cavern integrity project.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. ARO amounts are measured at their estimated fair value using expected present value techniques. Over time, the ARO liability is accreted to its present value (through accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-lived asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts.

See Note 5 for additional information regarding our property, plant and equipment and AROs.

Recent Accounting Developments

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

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

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

However, based on guidance in ASC 606 applicable to non-cash consideration, we will start recognizing revenue in connection with equity NGL volumes we receive as consideration for providing processing services under percent of liquids and similar arrangements. The value assigned to this non-cash consideration and related inventory will be based on the fair value of NGLs we are entitled to at the time the processing services are performed. An additional revenue stream, along with the related cost of sales, would be recognized in connection with the ultimate sale of the NGL products derived from the NGLs acquired as a fee for service. Under current accounting practice, we only recognize revenue from the downstream sale of NGL products and do not record service revenue. Based on our estimates, if the changes required by ASC 606 had been adopted at January 1, 2017, our total consolidated revenues for the year ended December 31, 2017 would have increased by approximately 1%.

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

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

Leases. In February 2016, the FASB issued ASC 842, *Leases* ("ASC 842"), which requires substantially all leases (with the exception of leases with a term of one year or less) to be recorded on the balance sheet using a method referred to as the right-of-use ("ROU") asset approach. We will adopt the new standard on January 1, 2019 using a proposed transition method that will require us to apply the new lease standard 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 have started the process of reviewing our lease agreements in light of the new guidance. Although we are in the early stages of our ASC 842 implementation project, we anticipate that this new lease guidance will result in changes to the way our operating leases are recorded, presented and disclosed in our consolidated financial statements.

Derivative instruments. In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*, which amends and simplifies existing guidance in order to allow companies to more accurately present the economic effects of risk management activities in the financial statements. As a result of the new guidance, we will no longer be required to separately measure and disclose the effect of periodic hedge ineffectiveness related to cash flow hedges. We early adopted this new guidance on January 1, 2018. The impact of the new guidance on our consolidated financial statements and disclosures is not expected to be material.

Note 3. Revenue Recognition

In general, we recognize revenue from our customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer's price is fixed or determinable and (iv) collectibility is reasonably assured. Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue. The following information summarizes our revenue recognition policies by business segment. See Note 2 for information regarding recent accounting guidance related to revenue recognition. See Note 10 for general information regarding our business segments.

The following table information regarding our consolidated revenues by business segment for the periods indicated:

	For the Year Ended December 31,		
	2017	2016	2015
NGL Pipelines & Services:			
Sales of NGLs and related products	$ 10,521.3	$ 8,380.5	$ 8,044.8
Midstream services	1,946.7	1,862.0	1,743.2
Total	12,468.0	10,242.5	9,788.0
Crude Oil Pipelines & Services:			
Sales of crude oil	7,365.2	5,802.5	9,732.9
Midstream services	791.6	712.5	573.0
Total	8,156.8	6,515.0	10,305.9
Natural Gas Pipelines & Services:			
Sales of natural gas	2,238.5	1,591.9	1,722.6
Midstream services	907.1	951.1	1,020.7
Total	3,145.6	2,543.0	2,743.3
Petrochemical & Refined Products Services:			
Sales of petrochemicals and refined products	4,696.3	2,921.9	3,333.5
Midstream services	774.8	799.9	778.4
Total	5,471.1	3,721.8	4,111.9
Offshore Pipelines & Services:			
Sales of crude oil	--	--	3.2
Midstream services	--	--	75.6
Total	--	--	78.8
Total consolidated revenues	$ 29,241.5	$ 23,022.3	$ 27,027.9

NGL Pipelines & Services

Sales of NGLs and related products

- NGL marketing activities generate revenues from merchant activities such as spot and term sales of NGLs and related products, which we take title to through our natural gas processing activities (i.e., our equity NGL production), and open market and long-term contract purchases. Revenue from these sales contracts is recognized when the NGLs are sold and delivered to customers at market-based prices.

Midstream services

- Natural gas processing utilizes 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. We recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts. When a cash fee for natural gas processing services is stipulated by a contract, we record revenue when a producer's natural gas has been processed and redelivered.

- NGL pipeline transportation contracts and tariffs generally generate revenue based upon a fixed fee per gallon of liquids multiplied by the volume transported and delivered (or capacity reserved). Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies or contractual arrangements. Under certain agreements customers are required to ship a minimum volume over an agreed-upon period with a provision that allows the shipper 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 at the earlier of when the deficiency volume is shipped, when the shipper's ability to meet the minimum volume commitment has expired, or when the pipeline is otherwise released from its performance obligation.

- NGL fractionation primarily generates revenue under fee-based arrangements. These fees are contractually subject to adjustment for changes in certain fractionation expenses (e.g., natural gas fuel costs) and are recognized in the period services are provided.

- NGL and related product storage contracts generate revenue from capacity reservation where we collect a fee for reserving storage capacity for customers in our underground storage wells. Under these agreements, revenue is recognized on a straight-line basis over the specified reservation period. In addition, we generally charge customers throughput fees based on volumes delivered into and subsequently withdrawn from storage, which are recognized as the service is provided.

- NGL import and export terminaling activities generate revenue in the period services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded.

Crude Oil Pipelines & Services

<u>Sales of crude oil</u>

- Crude oil marketing activities generate revenues from the sale and delivery of crude oil purchased either directly from producers or on the open market. Revenue from these sales contracts is recognized when crude oil is sold and delivered to customers at market-based prices.

<u>Midstream services</u>

- Crude oil transportation contracts and tariffs generally generate revenue based upon a fixed fee per barrel multiplied by the volume transported and delivered (or capacity reserved). Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies or contractual arrangements. Under certain agreements, customers are required to ship a minimum volume over an agreed-upon period, with make-up rights. Revenue pursuant to such agreements is initially deferred and subsequently recognized at the earlier of when the deficiency volume is shipped, when the shipper's ability to meet the minimum volume commitment has expired, or when the pipeline is otherwise released from its performance obligation.

- Condensate gathering, processing and stabilization services as well as crude oil gathering, treating and pumping services generate revenue based upon the higher of actual volumes handled or minimum volume commitments multiplied by predominantly fixed fees charged for the underlying services. The producer pays a deficiency fee when its volumes do not meet contractually defined minimum volume thresholds (these agreements have no make-up rights).

- Crude oil storage and terminaling agreements generate revenue based on capacity reservation where we collect a fee for reserving storage capacity for customers at our terminals. Under these agreements, revenue is recognized on a straight-line basis over the specified reservation period. In addition, customers are typically billed a fee per unit of volume loaded or unloaded at our terminals.

Natural Gas Pipelines & Services

<u>Sales of natural gas</u>

- Natural gas marketing activities generate revenue from the sale and delivery of natural gas purchased from producers, regional natural gas processing plants and on the open market. Revenue from these sales contracts is recognized when natural gas is sold and delivered to customers at market-based prices.

<u>Midstream services</u>

- Natural gas transportation contracts generate revenues based on a fee per unit of volume transported multiplied by the volume gathered or delivered. Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies or contractual arrangements. Certain of our natural gas pipelines offer firm capacity reservation services whereby the shipper pays a contractual fee based on the level of throughput capacity reserved (whether or not the shipper actually utilizes such capacity). Revenues are recognized when volumes have been delivered to customers or in the period we provide firm capacity reservation services.

- Natural gas storage contracts generate revenue typically by two components: (i) monthly demand payments, which are associated with a customer's storage capacity reservation and paid regardless of actual usage, and (ii) storage fees per unit of volume stored at our facilities. Revenue from demand payments is recognized during the period the customer reserves capacity. Revenue from storage fees is recognized in the period the services are provided.

Petrochemical & Refined Products Services

<u>*Sales of petrochemicals and refined products*</u>

- Our petrochemical marketing activities include the purchase and fractionation of refinery grade propylene obtained on the open market and generate revenues from the sale and delivery of polymer grade propylene to customers at market-based prices. Revenues from our propane dehydrogenation ("PDH") facility are dependent on the level of minimum volume commitments by customers and the associated contractual fees paid by them for polymer grade propylene during a given period.

- Revenue from the production and sale of octane additives and high purity isobutylene is dependent on the volume of such commodities sold and delivered to customers at market-based prices.

- Revenue from refined products marketing is dependent on the volume of such commodities purchased on the open market and sold and delivered to customers at market-based prices.

<u>*Midstream services*</u>

- Propylene fractionation, butane isomerization and deisobutanizer facilities generate revenue through fee-based toll arrangements with customers, with such arrangements typically including a base-processing fee subject to adjustment for changes in power, fuel and labor costs. Revenue resulting from such agreements is recognized in the period the services are provided.

- Petrochemical and refined products transportation contracts generate revenue based upon a fixed fee per volume multiplied by the volume transported and delivered. Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies or contractual arrangements.

- Refined products storage contracts generate revenue based on capacity reservation where we collect a fee for reserving a defined storage capacity for customers at our facilities. Under these contracts, revenue is recognized on a straight-line basis over the length of the storage period.

- Refined product terminaling contracts generate revenue based on a fee per unit of volume loaded or unloaded and are recognized in the period such services are provided.

- Marine transportation contracts generate revenue based on set day rates or a set fee per cargo movement recognized over the transit time of individual tows. Additionally, we record revenue for costs of fuel and other specified operational fees that are directly reimbursed by the customer under most of these contracts.

Offshore Pipelines & Services

In July 2015, we sold our Offshore Business, which comprised our Offshore Pipelines & Services segment. See Note 10 for additional information related to this sale.

Note 4. Inventories

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

	December 31, 2017	December 31, 2016
NGLs	$ 917.4	$ 1,156.1
Petrochemicals and refined products	161.5	220.7
Crude oil	516.3	360.0
Natural gas	14.6	33.7
Total	$ 1,609.8	$ 1,770.5

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to outright purchases from third parties for cash), these volumes are valued at market-based prices during the month in which they are acquired.

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 Year Ended December 31, 2017	2016	2015
Cost of sales (1)	$ 21,487.0	$ 15,710.9	$ 19,612.9
Lower of cost or net realizable value adjustments within cost of sales	9.1	11.5	19.8

(1) Cost of sales is a component of "Operating costs and expenses," as presented on our 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.

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. These non-cash charges are a component of cost of sales in the period they are recognized. To the extent our commodity hedging strategies address inventory-related price risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 14 for a description of our commodity hedging activities.

Note 5. 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	December 31, 2017	December 31, 2016
Plants, pipelines and facilities (1)	3-45 (5)	$ 37,132.2	$ 35,124.6
Underground and other storage facilities (2)	5-40 (6)	3,460.9	3,326.9
Transportation equipment (3)	3-10	177.1	165.8
Marine vessels (4)	15-30	803.8	800.7
Land		273.1	264.6
Construction in progress		4,698.1	3,320.7
Total		46,545.2	43,003.3
Less accumulated depreciation		10,924.8	9,710.8
Property, plant and equipment, net		$ 35,620.4	$ 33,292.5

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

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

	For the Year Ended December 31, 2017	2016	2015
Depreciation expense (1)	$ 1,296.1	$ 1,215.7	$ 1,161.6
Capitalized interest (2)	192.1	168.2	149.1

(1) Depreciation expense is a component of "Costs and expenses" as presented on our Statements of Consolidated Operations.
(2) Capitalized interest is a component of "Interest expense" as presented on our Statements of Consolidated Operations.

Asset Retirement Obligations

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

Property, plant and equipment at December 31, 2017 and 2016 includes $39.9 million and $44.9 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents information regarding our AROs for the periods indicated:

	For the Year Ended December 31, 2017	2016	2015
ARO liability beginning balance	$ 85.4	$ 58.5	$ 98.3
Liabilities incurred	4.7	4.2	2.7
Liabilities settled	(2.2)	(5.7)	(6.3)
Revisions in estimated cash flows	(6.7)	24.6	49.7
Accretion expense	5.5	3.8	5.2
AROs related to Offshore Business sold in July 2015	--	--	(91.1)
ARO liability ending balance	$ 86.7	$ 85.4	$ 58.5

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

2018	2019	2020	2021	2022
$ 5.8	$ 6.2	$ 6.5	$ 6.9	$ 7.3

Note 6. 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 December 31, 2017	December 31, 2017	December 31, 2016
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C. (“VESCO”)	13.1%	$ 25.7	$ 24.8
K/D/S Promix, L.L.C. (“Promix”)	50%	30.9	33.7
Baton Rouge Fractionators LLC (“BRF”)	32.2%	17.0	17.3
Skelly-Belvieu Pipeline Company, L.L.C. (“Skelly-Belvieu”)	50%	37.0	38.9
Texas Express Pipeline LLC (“Texas Express”)	35%	314.4	331.9
Texas Express Gathering LLC (“TEG”)	45%	35.9	35.8
Front Range Pipeline LLC (“Front Range”)	33.3%	165.7	165.4
Delaware Basin Gas Processing LLC (“Delaware Processing”)	50%	107.3	102.6
Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC (“Seaway”)	50%	1,378.9	1,393.8
Eagle Ford Pipeline LLC (“Eagle Ford Crude Oil Pipeline”)	50%	385.2	377.9
Eagle Ford Terminals Corpus Christi LLC (“Eagle Ford Corpus Christi”)	50%	75.1	52.9
Natural Gas Pipelines & Services:			
White River Hub, LLC (“White River Hub”)	50%	20.8	21.7
Petrochemical & Refined Products Services:			
Centennial Pipeline LLC (“Centennial”)	50%	60.8	62.3
Other	Various	4.7	18.3
Total investments in unconsolidated affiliates		$ 2,659.4	$ 2,677.3

NGL Pipelines & Services

The principal business activity of each investee included in our NGL Pipelines & Services segment is described as follows:

- VESCO owns a natural gas processing facility in south Louisiana and a related gathering system that gathers natural gas from certain offshore developments for delivery to its natural gas processing facility.

- Promix owns an NGL fractionation facility located in south Louisiana. The facility receives mixed NGLs via pipeline from natural gas processing plants located in southern Louisiana and along the Mississippi Gulf Coast. In addition, Promix owns an NGL gathering system that gathers mixed NGLs from processing plants in southern Louisiana for its fractionator.

- BRF owns an NGL fractionation facility located in south Louisiana that receives mixed NGLs from natural gas processing plants located in Alabama, Mississippi and southern Louisiana. In addition, BRF leases an NGL storage cavern.

- Skelly-Belvieu owns a pipeline that transports mixed NGLs from Skellytown, Texas to Mont Belvieu, Texas. The Skelly-Belvieu Pipeline receives NGLs through a pipeline interconnect with our Mid-America Pipeline System in Skellytown.

- Texas Express owns an NGL pipeline that extends from Skellytown to our NGL fractionation and storage complex in Mont Belvieu. Mixed NGLs from the Rocky Mountains, Permian Basin and Mid-Continent regions are delivered to the Texas Express Pipeline via an interconnect with our Mid-America Pipeline System near Skellytown. The pipeline also transports mixed NGLs from two gathering systems owned by TEG to Mont Belvieu. In addition, mixed NGLs from the Denver-Julesburg Basin in Colorado are transported to the Texas Express Pipeline using the Front Range Pipeline.

- TEG owns two NGL gathering systems that deliver mixed NGLs to the Texas Express Pipeline. The Elk City gathering system gathers mixed NGLs from natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and western Oklahoma. The North Texas gathering system gathers mixed NGLs from natural gas processing plants in the Barnett Shale production area in North Texas. An affiliate of Enbridge Energy Partners, L.P. serves as operator of these two NGL gathering systems.

- Front Range owns an NGL pipeline that transports mixed NGLs from natural gas processing plants located in the Denver-Julesburg Basin to an interconnect with our Texas Express Pipeline and Mid-America Pipeline System and other third party facilities in Skellytown.

- Delaware Processing, which commenced operations in August 2016, was formed with Occidental Petroleum Corporation to plan, design and construct a new 150 million cubic feet per day ("MMcf/d") cryogenic natural gas processing plant to accommodate the growing production of NGL-rich natural gas in the Delaware Basin, in West Texas and southern New Mexico. The facility, located in Reeves County, Texas, is supported by long-term, firm contracts. We served as construction manager for the project and serve as operator of the new facility.

Crude Oil Pipelines & Services
The principal business activity of each investee included in our Crude Oil Pipelines & Services segment is described as follows:

- Seaway owns a pipeline system that connects the Cushing, Oklahoma crude oil hub with markets in Southeast Texas. The Seaway Pipeline is comprised of the Longhaul System, the Freeport System and the Texas City System. The Cushing hub is a major industry trading hub and price settlement point for West Texas Intermediate on the NYMEX.

  The Longhaul System, which consists of two pipelines, provides north-to-south transportation of crude oil from the Cushing hub to Seaway's Jones Creek terminal near Freeport, Texas and a terminal that we own located near Katy, Texas. The second of these two pipelines is referred to as the "Seaway Loop."

  The Freeport System consists of a marine import and export dock, three pipelines and other related facilities that transport crude oil to and from Freeport and the Jones Creek terminal. The Texas City System consists of a marine import and export dock, storage tanks, various pipelines and other related facilities that transport crude oil to refineries in the Texas City, Texas area and to and from terminals in the Galena Park area, our Enterprise Crude Houston ("ECHO") terminal and locations along the Houston Ship Channel. The Texas City System also receives production from certain offshore Gulf of Mexico developments.

- Eagle Ford Crude Oil Pipeline owns a crude oil pipeline that transports crude oil and condensate for producers in South Texas. The system consists of a crude oil and condensate pipeline system originating in Gardendale, Texas in LaSalle County to Three Rivers, Texas in Live Oak County and extending to Corpus Christi, Texas. The system also includes a pipeline segment that interconnects with our South Texas Crude Oil Pipeline System in Wilson County. This system includes a marine terminal facility in Corpus Christi and storage capacity across the system.

- Eagle Ford Corpus Christi is a joint venture formed in March 2015 to construct and operate a new deep-water marine crude oil terminal that is designed to handle a variety of ocean-going vessels. The new terminal is expected to be placed into service during the third quarter of 2018.

Natural Gas Pipelines & Services

White River Hub owns a natural gas hub facility serving producers in the Piceance Basin of northwest Colorado. The facility enables producers to access six interstate natural gas pipelines.

Petrochemical & Refined Products Services

The principal business activity of each significant investee included in our Petrochemical & Refined Products Services segment is described as follows:

- BRPC owns a propylene fractionation facility located in south Louisiana that fractionates refinery grade propylene into chemical grade propylene.

- Centennial owns an interstate refined products pipeline that extends from Beaumont, Texas, to Bourbon, Illinois. Centennial also owns a refined products storage terminal located near Creal Springs, Illinois.

Equity Earnings

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

	For the Year Ended December 31,		
	2017	2016	2015
NGL Pipelines & Services	$ 73.4	$ 61.4	$ 57.5
Crude Oil Pipelines & Services	358.4	311.9	281.4
Natural Gas Pipelines & Services	3.8	3.8	3.8
Petrochemical & Refined Products Services (1)	(9.6)	(15.1)	(15.7)
Offshore Pipelines & Services (2)	--	--	46.6
Total	$ 426.0	$ 362.0	$ 373.6

(1) Losses are primarily attributable to our investment in Centennial. As a result of a trend in declining earnings, we estimated the fair value of this equity-method investment during each of the last three fiscal years. Our estimates, based on a combination of market and income approaches, indicate that the fair value of this investment remains in excess of its carrying value.

(2) Our investments in unconsolidated affiliates classified within the Offshore Pipelines & Services segment were sold in July 2015 (see Note 10).

Excess Cost

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

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

	December 31, 2017	December 31, 2016
NGL Pipelines & Services	$ 22.9	$ 24.1
Crude Oil Pipelines & Services	18.2	19.0
Petrochemical & Refined Products Services	1.8	2.1
Total	$ 42.9	$ 45.2

In total, amortization of excess cost amounts were $2.1 million, $2.1 million and $4.9 million for the years ended December 31, 2017, 2016 and 2015, respectively. We forecast that our amortization of excess cost amount will approximate $2.2 million in each of the next five years.

Summarized Combined Financial Information of Unconsolidated Affiliates

Combined balance sheet information for the last two years and results of operations data for the last three years for our unconsolidated affiliates are summarized in the following table (all data presented on a 100% basis):

	December 31, 2017	December 31, 2016
Balance Sheet Data:		
Current assets	$ 288.8	$ 199.5
Property, plant and equipment, net	5,509.7	5,644.4
Other assets	71.2	61.5
Total assets	$ 5,869.7	$ 5,905.4
Current liabilities	$ 233.5	$ 208.5
Other liabilities	84.8	112.3
Combined equity	5,551.4	5,584.6
Total liabilities and combined equity	$ 5,869.7	$ 5,905.4

	For the Year Ended December 31, 2017	2016	2015
Income Statement Data:			
Revenues	$ 1,509.0	$ 1,342.0	$ 1,426.6
Operating income	925.9	786.7	825.8
Net income	929.5	781.7	814.1

Note 7. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	December 31, 2017			December 31, 2016		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 447.4	$ (187.5)	$ 259.9	$ 447.4	$ (172.7)	$ 274.7
Contract-based intangibles	280.8	(218.4)	62.4	279.9	(204.4)	75.5
Segment total	728.2	(405.9)	322.3	727.3	(377.1)	350.2
Crude Oil Pipelines & Services:						
Customer relationship intangibles	2,203.5	(127.0)	2,076.5	2,204.4	(84.5)	2,119.9
Contract-based intangibles	281.0	(171.0)	110.0	281.0	(121.9)	159.1
Segment total	2,484.5	(298.0)	2,186.5	2,485.4	(206.4)	2,279.0
Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,350.3	(417.1)	933.2	1,350.3	(390.0)	960.3
Contract-based intangibles	464.7	(379.5)	85.2	464.7	(370.5)	94.2
Segment total	1,815.0	(796.6)	1,018.4	1,815.0	(760.5)	1,054.5
Petrochemical & Refined Products Services:						
Customer relationship intangibles	181.4	(45.9)	135.5	185.5	(43.9)	141.6
Contract-based intangibles	46.0	(18.4)	27.6	54.0	(15.2)	38.8
Segment total	227.4	(64.3)	163.1	239.5	(59.1)	180.4
Total intangible assets	$ 5,255.1	$ (1,564.8)	$ 3,690.3	$ 5,267.2	$ (1,403.1)	$ 3,864.1

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

	For the Year Ended December 31,		
	2017	2016	2015
NGL Pipelines & Services	$ 28.9	$ 30.6	$ 33.6
Crude Oil Pipelines & Services	92.5	98.4	87.1
Natural Gas Pipelines & Services	36.2	33.2	40.0
Petrochemical & Refined Products Services	9.3	9.1	8.9
Offshore Pipelines & Services	--	--	4.5
Total	$ 166.9	$ 171.3	$ 174.1

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

2018	2019	2020	2021	2022
$ 174.5	$ 165.8	$ 150.7	$ 145.6	$ 141.6

In general, our intangible assets fall within two categories – customer relationship and contract-based intangible assets. The values assigned to such intangible assets are amortized to earnings using either (i) a straight-line approach or (ii) other methods that closely resemble the pattern in which the economic benefits are estimated to be consumed or otherwise used, as appropriate.

Customer relationship intangible assets. Customer relationship intangible assets represent the estimated economic value assigned to commercial relationships acquired in connection with business combinations. Our customer relationship intangible assets can be classified as either (i) basin-specific or (ii) general. In certain instances, the acquisition of these intangible assets represents obtaining access to customers in a defined resource basin analogous to having a franchise in a particular area. Efficient operation of the acquired assets (e.g., a natural gas gathering system) helps to support commercial relationships with existing producers and provides us with opportunities to establish new ones within our existing asset footprint. The duration of such customer relationships is limited by the estimated economic life of the associated resource basin. In other situations, the acquisition of a customer relationship intangible asset provides us with access to customers whose hydrocarbon volumes are not attributable to specific resource basins. As with basin-specific customer relationships, efficient operation of the associated assets (e.g., a marine terminal that handles volumes originating from multiple sources) helps to support commercial relationships with existing customers and provides us with opportunities to establish new ones. The duration of these general customer relationships is typically limited to the term of the underlying service contracts, including assumed renewals.

Amortization expense attributable to customer relationships is recorded in a manner that closely resembles the pattern in which we expect to benefit from providing services to customers.

At December 31, 2017, the carrying value of our portfolio of customer relationship intangible assets was $3.4 billion, the principal components of which are as follows:

	Weighted Average Remaining Amortization Period	December 31, 2017 Gross Value	Accumulated Amortization	Carrying Value
Basin-specific customer relationships:				
EFS Midstream (1)	24.4 years	$ 1,409.8	$ (88.8)	$ 1,321.0
State Line and Fairplay (2)	29.2 years	895.0	(164.7)	730.3
San Juan Gathering (3)	21.8 years	331.3	(218.0)	113.3
Encinal (4)	9.0 years	132.9	(98.4)	34.5
General customer relationships:				
Oiltanking (5)	26.0 years	1,192.5	(57.1)	1,135.4

(1) We acquired these intangible assets in connection with our acquisition of EFS Midstream in July 2015 (see Note 12 for additional information).
(2) These customer relationships are associated with our State Line and Fairplay Gathering Systems, which we acquired in 2010. The State Line system serves producers in the Haynesville and Bossier Shale supply basins and the Cotton Valley formation in Louisiana and eastern Texas. The Fairplay system serves producers in the Cotton Valley formation within Panola and Rusk counties in East Texas.
(3) These customer relationships are associated with our San Juan Gathering System, which serves producers in the San Juan Basin of northern New Mexico and southern Colorado. We acquired this intangible asset in 2004.
(4) These customer relationships are associated with our Encinal Gathering System, which serves producers in the Olmos and Wilcox formations in South Texas. We acquired this intangible asset in 2006.
(5) We acquired these intangible assets in connection with our acquisition of Oiltanking in October 2014 (see Note 12 for additional information).

EFS Midstream customer relationships
The EFS Midstream System serves producers in the Eagle Ford Shale, providing condensate gathering and processing services as well as gathering, treating and compression services for associated natural gas. The estimated fair value of these customer relationship intangible assets was determined using an income approach, specifically a discounted cash flow analysis. The EFS Midstream customer relationships provide us with long-term access to the natural gas, NGL and condensate resources served by EFS Midstream. Infrastructure like that owned by EFS Midstream requires a significant investment, both in terms of initial construction costs and ongoing maintenance, and is generally supported by long-term contracts with producers (e.g., PXD and Reliance) that establish a customer base. The level of expenditures involved in constructing these asset networks can create significant economic barriers to entry that effectively limit competition. The long-term nature of the underlying producer contracts and limited risk of competition ensure a long commercial relationship with existing producers.

The discounted cash flow analysis used to estimate the fair value of the EFS Midstream customer relationships relied on Level 3 fair value inputs, including long-range cash flow forecasts that extend for the estimated economic life of the hydrocarbon resource base served by the asset network, anticipated service contract renewals and resource base depletion rates. A discount rate of 15% was applied to the resulting cash flows.

Oiltanking customer relationships
These intangible assets represent the estimated value of the expected patronage of Oiltanking's third party storage and terminal customers.

We valued the customer relationships using an income approach, specifically a discounted cash flow analysis. Our analysis was based on forecasting revenue for the existing terminal customers, including assumed service contract renewals, and then adjusting for expected customer attrition rates. The operating cash flows were then reduced by contributory asset charges. The cash flow projections were based on forecasts used to price the Oiltanking acquisition.

The discounted cash flow analysis used to estimate the fair value of the Oiltanking customer relationships relied on Level 3 fair value inputs, including long-range cash flow forecasts that extend for the estimated economic life of the terminal assets and anticipated service contract renewals. A discount rate of 6.5% was applied to the resulting cash flows.

Contract-based intangible assets. Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations or asset purchases. At December 31, 2017, the carrying value of our contract-based intangible assets was $285.2 million. Our most significant contract-based intangible assets are the Oiltanking customer contracts and the Jonah natural gas gathering agreements.

Oiltanking customer contracts
We recorded $297.4 million of contract-based intangible assets in connection with our acquisition of Oiltanking in October 2014. These intangible assets represent the estimated value of specific commercial rights we acquired in connection with third party customer storage and terminal contracts at the Houston and Beaumont terminals. We valued the contracts using an income approach. If a contract was in its renewal period and had not been cancelled, we assumed the contract was renewed on equivalent terms to the prior contract. We only valued those contracts that specified a minimum monthly fee, excluding contracts with a de minimis fee.

At December 31, 2017, the carrying value of this group of intangible assets was $118.7 million and the weighted average remaining amortization period for the group was 4.2 years. Amortization expense attributable to these contracts is recorded using a straight-line approach over the terms of the underlying contracts.

Jonah natural gas gathering agreements
These intangible assets represent the value attributed to certain natural gas gathering contracts on the Jonah Gathering System. At December 31, 2017, the carrying value of this group of intangible assets was $63.9 million and the weighted average remaining amortization period for the group was 24 years. Amortization expense attributable to these intangible assets is recorded using a units-of-production method based on gathering volumes.

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. Goodwill is not amortized; however, it is subject to annual impairment testing at the end of each fiscal year, and more frequently, if circumstances indicate it is probable that the fair value of goodwill is below its carrying amount. The following table presents changes in the carrying amount of goodwill during the periods indicated:

	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Offshore Pipelines & Services	Consolidated Total
Balance at January 1, 2015	$ 2,210.2	$ 918.7	$ 296.3	$ 793.0	$ 82.0	$ 4,300.2
Reclassification of Oiltanking IDR balances to goodwill in connection with the cancellation of such rights and other adjustments	432.6	850.7	--	170.8	--	1,454.1
Reduction in goodwill related to the sale of assets	--	(2.1)	--	--	(82.0)	(84.1)
Addition to goodwill related to the acquisition of EFS Midstream	8.9	73.7	--	--	--	82.6
Goodwill reclassified to assets held-for-sale	--	--	--	(7.6)	--	(7.6)
Balance at December 31, 2015	2,651.7	1,841.0	296.3	956.2	--	5,745.2
Balance at December 31, 2016	2,651.7	1,841.0	296.3	956.2	--	5,745.2
Balance at December 31, 2017	$ 2,651.7	$ 1,841.0	$ 296.3	$ 956.2	$ --	$ 5,745.2

We did not record any goodwill impairment charges during the years ended December 31, 2017, 2016 or 2015. Based on our most recent goodwill impairment test at December 31, 2017, each reporting unit's fair value was substantially in excess of its carrying value (i.e., by at least 10%).

Upon completion of Step 2 of the Oiltanking acquisition in February 2015, the IDRs of Oiltanking were cancelled and the associated $1.45 billion carrying value of this identifiable intangible asset was reclassified to goodwill. In the aggregate, we recorded $3.67 billion of goodwill in connection with the Oiltanking acquisition. Factors contributing to the recognition of goodwill in the Oiltanking acquisition include (i) opportunities for new business and repurposing existing assets for "best use" in order to meet anticipated increased demand for export and logistical services related to North American crude oil, condensate and NGL production, (ii) securing ownership and control of assets that are essential to our other midstream assets and (iii) cost savings from integrating Oiltanking's operations into our midstream asset network. See Note 12 for additional information regarding the Oiltanking acquisition.

In July 2015, we recorded $82.6 million of goodwill in connection with our acquisition of EFS Midstream (see Note 12). In general, we attribute this goodwill to our ability to leverage the acquired business with our existing midstream asset network to create future business opportunities.

In July 2015, we removed $82.0 million of goodwill in connection with sale of the Offshore Business (see Note 10).

Note 8. Debt Obligations

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

	December 31, 2017	December 31, 2016
EPO senior debt obligations:		
Commercial Paper Notes, variable-rates	$ 1,755.7	$ 1,777.2
Senior Notes L, 6.30% fixed-rate, due September 2017	--	800.0
Senior Notes V, 6.65% fixed-rate, due April 2018	349.7	349.7
Senior Notes OO, 1.65% fixed-rate, due May 2018	750.0	750.0
364-Day Revolving Credit Agreement, variable-rate, due September 2018	--	--
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
Senior Notes LL, 2.55% fixed-rate, due October 2019	800.0	800.0
Senior Notes Q, 5.25% fixed-rate, due January 2020	500.0	500.0
Senior Notes Y, 5.20% fixed-rate, due September 2020	1,000.0	1,000.0
Senior Notes RR, 2.85% fixed-rate, due April 2021	575.0	575.0
Senior Notes CC, 4.05% fixed-rate, due February 2022	650.0	650.0
Multi-Year Revolving Credit Facility, variable-rate, due September 2022	--	--
Senior Notes HH, 3.35% fixed-rate, due March 2023	1,250.0	1,250.0
Senior Notes JJ, 3.90% fixed-rate, due February 2024	850.0	850.0
Senior Notes MM, 3.75% fixed-rate, due February 2025	1,150.0	1,150.0
Senior Notes PP, 3.70% fixed-rate, due February 2026	875.0	875.0
Senior Notes SS, 3.95% fixed-rate, due February 2027	575.0	575.0
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes W, 7.55% fixed-rate, due April 2038	399.6	399.6
Senior Notes R, 6.125% fixed-rate, due October 2039	600.0	600.0
Senior Notes Z, 6.45% fixed-rate, due September 2040	600.0	600.0
Senior Notes BB, 5.95% fixed-rate, due February 2041	750.0	750.0
Senior Notes DD, 5.70% fixed-rate, due February 2042	600.0	600.0
Senior Notes EE, 4.85% fixed-rate, due August 2042	750.0	750.0
Senior Notes GG, 4.45% fixed-rate, due February 2043	1,100.0	1,100.0
Senior Notes II, 4.85% fixed-rate, due March 2044	1,400.0	1,400.0
Senior Notes KK, 5.10% fixed-rate, due February 2045	1,150.0	1,150.0
Senior Notes QQ, 4.90% fixed-rate, due May 2046	975.0	975.0
Senior Notes NN, 4.95% fixed-rate, due October 2054	400.0	400.0
TEPPCO senior debt obligations:		
TEPPCO Senior Notes, 6.65% fixed-rate, due April 2018	0.3	0.3
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	0.4	0.4
Total principal amount of senior debt obligations	21,605.7	22,427.2
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066 (1)	521.1	521.1
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 (2)	256.4	256.4
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068 (3)	682.7	682.7
EPO Junior Subordinated Notes D, fixed/variable-rate, due August 2077 (4)	700.0	--
EPO Junior Subordinated Notes E, fixed/variable-rate, due August 2077 (5)	1,000.0	--
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2
Total principal amount of senior and junior debt obligations	24,780.1	23,901.6
Other, non-principal amounts	(211.4)	(203.9)
Less current maturities of debt	(2,855.0)	(2,576.8)
Total long-term debt	$ 21,713.7	$ 21,120.9

(1) Variable rate is reset quarterly and based on 3-month LIBOR plus 3.708%.
(2) Fixed rate of 7.000% through May 31, 2017; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 2.778%.
(3) Fixed rate of 7.034% through January 14, 2018; thereafter, the rate will be the greater of 7.034% or a variable rate reset quarterly and based on 3-month LIBOR plus 2.680%. These notes are expected to be redeemed in March 2018 (see Note 22).
(4) Fixed rate of 4.875% through August 15, 2022; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 2.986%.
(5) Fixed rate of 5.250% through August 15, 2027; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 3.033%.

See Note 22, *Subsequent Events*, for information regarding the issuance of Senior Notes TT and UU and Junior Subordinated Notes F in February 2018 and the expected redemption of Junior Subordinated Notes B in March 2018.

Information Regarding Variable Interest Rates Paid

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt during the year ended December 31, 2017:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
Commercial Paper Notes	0.90% to 1.80%	1.34%
Multi-Year Revolving Credit Facility	2.23% to 2.23%	2.23%
EPO Junior Subordinated Notes A	4.59% to 5.08%	4.89%
EPO Junior Subordinated Notes C	3.98% to 4.26%	4.07%

The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at December 31, 2017 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt					
	Total	2018	2019	2020	2021	2022	Thereafter
Commercial Paper Notes	$ 1,755.7	$ 1,755.7	$ --	$ --	$ --	$ --	$ --
Senior Notes	19,850.0	1,100.0	1,500.0	1,500.0	575.0	650.0	14,525.0
Junior Subordinated Notes	3,174.4	--	--	--	--	--	3,174.4
Total	$ 24,780.1	$ 2,855.7	$ 1,500.0	$ 1,500.0	$ 575.0	$ 650.0	$ 17,699.4

Parent-Subsidiary Guarantor Relationships

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

EPO Debt Obligations

Commercial Paper Notes. EPO maintains a commercial paper program under which it may issue (and have outstanding at any time) up to $2.5 billion in the aggregate of short-term notes. As a back-stop to the program, we intend to maintain a minimum available borrowing capacity under EPO's Multi-Year Revolving Credit Facility equal to the aggregate amount outstanding under our commercial paper notes. All commercial paper notes issued under the program are senior unsecured obligations of EPO that are unconditionally guaranteed by Enterprise Products Partners L.P.

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

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

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

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

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

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

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

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

Senior Notes. EPO's fixed-rate senior notes are unsecured obligations of EPO that rank equal with its existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. EPO's senior notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict its ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions. In total, EPO issued $1.25 billion and $2.5 billion of senior notes during the years ended December 31, 2016 and 2015, respectively.

See Note 22, *Subsequent Events*, for information regarding the issuance of Senior Notes TT and UU in February 2018.

EPO Junior Subordinated Notes. EPO's payment obligations under its junior notes are subordinated to all of its current and future senior indebtedness (as defined in the related indenture agreement). Enterprise Products Partners L.P. guarantees repayment of amounts due under these junior notes through an unsecured and subordinated guarantee. The indenture agreement governing these notes allows EPO to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. Subject to certain exceptions, during any period in which interest payments are deferred, neither we nor EPO can declare or make any distributions on any of our respective equity securities or make any payments on indebtedness or other obligations that rank equal with or are subordinate to our junior notes. Each series of our junior notes rank equal with each other. Generally, each series of junior notes are not redeemable by EPO while such notes bear interest at a fixed annual rate.

In connection with the issuance of each series of junior notes, other than Junior Notes D and Junior Notes E (in each case, as defined below), EPO entered into separate Replacement Capital Covenants in favor of covered debt holders (as defined in the underlying documents) pursuant to which EPO agreed, for the benefit of such debt holders, that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made using proceeds from the issuance of certain securities.

In August 2017, EPO issued a combined $1.7 billion in principal amount of junior subordinated notes. The EPO Junior Subordinated Notes D ("Junior Notes D"), which were issued at $700 million principal amount in the aggregate, are redeemable at EPO's option, in whole or in part, on one or more occasions, on or after August 16, 2022 (the non-call 5 notes) at 100% of their principal amount, plus any accrued and unpaid interest. Junior Notes D bear interest at a fixed rate of 4.875% per year through August 15, 2022. Beginning August 16, 2022, Junior Notes D will bear interest at a floating rate based on a three-month LIBOR rate plus 2.986%, reset quarterly. Junior Notes D mature in August 2077.

The EPO Junior Subordinated Notes E ("Junior Notes E"), which were issued at $1.0 billion principal amount in the aggregate, are redeemable at EPO's option, in whole or in part, on one or more occasions, on or after August 16, 2027 (the non-call 10 notes) at 100% of their principal amount, plus any accrued and unpaid interest. Junior Notes E bear interest at a fixed rate of 5.25% per year through August 15, 2027. Beginning August 16, 2027, Junior Notes E will bear interest at a floating rate based on a three-month LIBOR rate plus 3.033%, reset quarterly. Junior Notes E also mature in August 2077.

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

The following table summarizes the interest rate terms of our junior subordinated notes:

Series	Fixed Annual Interest Rate	Variable Annual Interest Rate Thereafter
EPO Junior Subordinated Notes A	8.375% through July 31, 2016 (1)	3-month LIBOR rate + 3.708% (6)
EPO Junior Subordinated Notes B	7.034% through January 14, 2018 (2)	Greater of: (i) 3-month LIBOR rate + 2.680% or (ii) 7.034% (7)
EPO Junior Subordinated Notes C	7.000% through May 31, 2017 (3)	3-month LIBOR rate + 2.778% (8)
EPO Junior Subordinated Notes D	4.875% through August 15, 2022 (4)	3-month LIBOR rate + 2.986% (9)
EPO Junior Subordinated Notes E	5.250% through August 15, 2027 (5)	3-month LIBOR rate + 3.033% (10)

(1) Interest is payable semi-annually in arrears in February and August of each year, which commenced in February 2007.
(2) Interest was payable semi-annually in arrears in January and July of each year, which commenced in January 2008.
(3) Interest is payable semi-annually in arrears in June and December of each year, which commenced in December 2009.
(4) Interest is payable semi-annually in arrears in February and August of each year, which commenced in February 2018.
(5) Interest is payable semi-annually in arrears in February and August of each year, which commenced in February 2018.
(6) Interest is payable quarterly in arrears in February, May, August and November of each, which commenced in November 2016.
(7) Interest was payable quarterly in arrears in January, April, July and October of each year commencing in April 2018.
(8) Interest is payable quarterly in arrears in March, June, September and December of each year, which commenced in September 2017.
(9) Interest is payable quarterly in arrears in February, May, August and November of each year commencing in November 2022.
(10) Interest is payable quarterly in arrears in February, May, August and November of each year commencing in November 2027.

See Note 22, *Subsequent Events*, for information regarding the issuance of Junior Subordinated Notes F in February 2018 and the expected redemption of all $682.7 million aggregate principal amount of Junior Subordinated Notes B in March 2018.

Letters of Credit

At December 31, 2017, EPO had $66.4 million of letters of credit outstanding primarily related to our commodity hedging activities.

Lender Financial Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at December 31, 2017.

Note 9. Equity and Distributions

Partners Equity

Partners' equity reflects the various classes of limited partner interests (i.e., common units, including restricted common units) outstanding. The following table summarizes changes in the number of our outstanding units since January 1, 2015:

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
Number of units outstanding at January 1, 2015	1,933,095,027	4,229,790	1,937,324,817
Common units issued in connection with ATM program	25,520,424	--	25,520,424
Common units issued in connection with DRIP and EUPP	12,793,913	--	12,793,913
Common units issued in connection with Step 2 of Oiltanking acquisition	36,827,517	--	36,827,517
Common units issued in connection with the vesting and exercise of unit options	396,158	--	396,158
Common units issued in connection with the vesting of phantom unit awards	618,395	--	618,395
Common units issued in connection with the vesting of restricted common unit awards	2,009,970	(2,009,970)	--
Forfeiture of restricted common unit awards	--	(259,300)	(259,300)
Cancellation of treasury units acquired in connection with the vesting of equity-based awards	(683,954)	--	(683,954)
Other	15,054	--	15,054
Number of units outstanding at December 31, 2015	2,010,592,504	1,960,520	2,012,553,024
Common units issued in connection with ATM program	87,867,037	--	87,867,037
Common units issued in connection with DRIP and EUPP	16,316,534	--	16,316,534
Common units issued in connection with the vesting of phantom unit awards	1,761,455	--	1,761,455
Common units issued in connection with the vesting of restricted common unit awards	1,234,502	(1,234,502)	--
Forfeiture of restricted common unit awards	--	(43,724)	(43,724)
Cancellation of treasury units acquired in connection with the vesting of equity-based awards	(1,000,619)	--	(1,000,619)
Other	134,707	--	134,707
Number of units outstanding at December 31, 2016	2,116,906,120	682,294	2,117,588,414
Common units issued in connection with ATM program	21,807,726	--	21,807,726
Common units issued in connection with DRIP and EUPP	19,046,019	--	19,046,019
Common units issued in connection with the vesting of phantom unit awards	2,485,580	--	2,485,580
Common units issued in connection with the vesting of restricted common unit awards	681,044	(681,044)	--
Forfeiture of restricted common unit awards	--	(1,250)	(1,250)
Cancellation of treasury units acquired in connection with the vesting of equity-based awards	(1,027,798)	--	(1,027,798)
Common units issued in connection with employee compensation	1,176,103	--	1,176,103
Other	14,685	--	14,685
Number of units outstanding at December 31, 2017	2,161,089,479	--	2,161,089,479

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Sixth Amended and Restated Agreement of Limited Partnership (as amended from time to time, the "Partnership Agreement"). We are managed by our general partner, Enterprise GP.

In accordance with our Partnership Agreement, capital accounts are maintained for our limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity amounts presented in our consolidated financial statements prepared in accordance with GAAP. Earnings and cash distributions are allocated to holders of our common units in accordance with their respective percentage interests.

The net cash proceeds we received from the issuance of common units during the year ended December 31, 2017 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and revolving credit facilities and for general partnership purposes.

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. In total, EPO issued \$1.7 billion of junior notes, and \$1.25 billion and \$2.5 billion of senior notes during the years ended December 31, 2017, 2016 and 2015, respectively. See Note 8 for information regarding an offering of junior notes we completed in August 2017 using the 2016 Shelf.

See Note 22, Subsequent Events, for information regarding the issuance of senior notes and junior subordinated notes in February 2018 using the 2016 Shelf.

At-the-Market ("ATM") Program. In November 2017, we filed an amended registration statement 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. The new registration statement was declared effective on November 20, 2017 and replaced our prior registration statement with respect to the ATM program.

During 2017, we issued 21,807,726 common units under the ATM program for aggregate gross cash proceeds of \$603.1 million, resulting in total net cash proceeds of \$597.0 million. During 2016, we issued 87,867,037 common units under the ATM program for aggregate gross cash proceeds of \$2.17 billion, resulting in total net cash proceeds of \$2.16 billion. This includes 3,830,256 common units sold in January 2016 to privately held affiliates of EPCO, which generated gross proceeds of \$100 million. During 2015, we issued 25,520,424 common units under the ATM for aggregate gross cash proceeds of \$825.4 million, resulting in total net cash proceeds of \$817.4 million. This includes 3,225,057 common units sold in March 2015 to a privately held affiliate of EPCO, which generated gross proceeds of \$100 million.

Following the effectiveness of the new registration statement and after taking into account the aggregate sales price of common units sold under the ATM program through December 31, 2017, 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 at a discount ranging from 0% to 5% (currently set at 2.5% beginning with the distribution declared with respect to the fourth quarter of 2017 and paid in February 2018).

Activity under our DRIP for the last three years was as follows: 18,541,355 common units issued during 2017, which generated net cash proceeds of \$462.9 million; 15,809,503 common units issued during 2016, which generated net cash proceeds of \$374.0 million; and 12,413,351 common units issued during 2015, which generated net cash proceeds of \$359.8 million. Privately held affiliates of EPCO reinvested \$100 million through the DRIP in each of the years ended December 31, 2017, 2016 and 2015 (this amount being a component of the net cash proceeds presented for each period).

After taking into account the number of common units issued under the DRIP through December 31, 2017, we have the capacity to issue an additional 80,717,140 common units under this plan.

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"). Activity under our EUPP for the last three years was as follows: 504,664 common units issued during 2017, which generated net cash proceeds of \$13.5 million; 507,031 common units issued during 2016, which generated net cash proceeds of \$12.7 million; and 380,562 common units issued during 2015, which generated net cash proceeds of \$11.4 million.

After taking into account the number of common units issued under the EUPP through December 31, 2017, we may issue an additional 5,760,811 common units under this plan.

Completion of Oiltanking Acquisition. In accordance with the merger agreement and Oiltanking's partnership agreement, the merger was submitted to a vote of Oiltanking's common unitholders, with the required majority of unitholders (including our ownership interests) voting to approve the merger on February 13, 2015. Upon approval of the merger, a total of 36,827,517 of our common units were issued to Oiltanking's former public unitholders.

Step 2 of the acquisition was accounted for in accordance with ASC Topic 810, *Consolidations – Overall – Changes in Parent's Ownership Interest in a Subsidiary*. Since we had a controlling financial interest in Oiltanking before and after completion of Step 2, the increase in our ownership interest in Oiltanking was accounted for as an equity transaction with no gain or loss recognized. Step 2 represented our acquisition of the noncontrolling interests in Oiltanking; therefore, approximately $1.4 billion of noncontrolling interests attributable to Oiltanking was reclassified to limited partners' equity to reflect the February 2015 issuance of 36,827,517 new common units.

Registration Rights Agreement. In order to fund the equity consideration paid in Step 1 of the Oiltanking acquisition (see Note 12), we issued 54,807,352 common units to OTA on October 1, 2014 in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof, and we granted OTA registration rights with respect to these common units under a Registration Rights Agreement between us and OTA (the "Registration Rights Agreement"). The Registration Rights Agreement provides that, subject to the terms and conditions set forth therein, at any time after the earlier of (i) 90 days after October 1, 2014 and (ii) the execution of definitive agreements to acquire (through merger or otherwise) all or substantially all of the Oiltanking common units not owned by Enterprise or its affiliates, OTA may request that we prepare and file a registration statement to permit and otherwise facilitate the public resale of all or a portion of the 54,807,352 Enterprise common units that OTA owns. Our obligation to OTA to effect such transactions is limited to five registration statements and underwritten offerings.

Common units issued in connection with employee compensation. In February 2017, the dollar value of discretionary employee bonus payments with respect to the year ended December 31, 2016 (less any retirement plan deductions and withholding taxes) was remitted through the issuance of an equivalent value of newly issued Enterprise common units under EPCO's 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) ("2008 Plan"). We issued 1,176,103 common units, which had a value of $33.7 million, in connection with the employee bonus payments. The compensation expense associated with this issuance of common units was recognized during the year ended December 31, 2016. See Note 13 for additional information regarding the 2008 Plan.

Treasury Units. In December 1998, we announced a common unit repurchase program whereby we, together with certain affiliates, intended to repurchase up to 4,000,000 of our common units. A total of 2,763,200 common units were repurchased under this program; however, no repurchases have been made since 2002. As of December 31, 2017, we and our affiliates could repurchase up to 1,236,800 additional common units under this program.

A total of 681,044 restricted common unit awards granted to employees of EPCO vested and converted to common units during the year ended December 31, 2017. Of this amount, 229,910 were sold back to us by employees to cover related withholding tax requirements. In addition, 797,888 units were sold back to us by employees to cover withholding tax requirements related to the vesting of phantom unit awards. The total cost of these treasury unit purchases was approximately $29.5 million. We cancelled such treasury units immediately upon acquisition. See Note 13 for additional information regarding our equity-based awards.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive income (loss) primarily reflects the effective portion of the gain or loss on derivative instruments designated and qualified as cash flow hedges. Gain or loss amounts related to cash flow hedges recorded in accumulated other comprehensive income (loss) are reclassified to earnings in the same period(s) in which the underlying hedged forecasted transactions affect earnings. If it becomes probable that a forecasted transaction will not occur, the related net gain or loss in accumulated other comprehensive income (loss) is immediately reclassified into earnings.

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

	Gains (Losses) on Cash Flow Hedges: Commodity Derivative Instruments	Gains (Losses) on Cash Flow Hedges: Interest Rate Derivative Instruments	Other	Total
Balance, December 31, 2015	$ 56.6	$ (279.5)	$ 3.7	$ (219.2)
Other comprehensive income (loss) before reclassifications	(193.8)	42.3	(0.1)	(151.6)
Amounts reclassified from accumulated other comprehensive loss	53.4	37.4	--	90.8
Total other comprehensive income (loss)	(140.4)	79.7	(0.1)	(60.8)
Balance, December 31, 2016	(83.8)	(199.8)	3.6	(280.0)
Other comprehensive income (loss) before reclassifications	(38.5)	(5.7)	(0.1)	(44.3)
Amounts reclassified from accumulated other comprehensive loss	112.2	40.4	--	152.6
Total other comprehensive income (loss)	73.7	34.7	(0.1)	108.3
Balance, December 31, 2017	$ (10.1)	$ (165.1)	$ 3.5	$ (171.7)

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

	Location	For the Year Ended December 31, 2017	2016
Losses (gains) on cash flow hedges:			
Interest rate derivatives	Interest expense	$ 40.4	$ 37.4
Commodity derivatives	Revenue	111.6	53.6
Commodity derivatives	Operating costs and expenses	0.6	(0.2)
Total		$ 152.6	$ 90.8

Noncontrolling Interests

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

We reclassified approximately $1.4 billion of noncontrolling interests to limited partners' equity in connection with completing Step 2 of the Oiltanking acquisition in February 2015 (see Note 12). Cash distributions paid in the first quarter of 2015 to the limited partners of Oiltanking other than EPO and its subsidiaries are presented as amounts paid to noncontrolling interests.

The following table presents the components of net income attributable to noncontrolling interests as presented on our Statements of Consolidated Operations for the periods indicated:

	For the Year Ended December 31, 2017	2016	2015
Limited partners of Oiltanking other than EPO	$ --	$ --	$ 7.8
Joint venture partners	56.3	39.9	29.4
Total	$ 56.3	$ 39.9	$ 37.2

The following table presents cash distributions paid to and cash contributions received from noncontrolling interests as presented on our Statements of Consolidated Cash Flows and Statements of Consolidated Equity for the periods indicated:

	For the Year Ended December 31,		
	2017	2016	2015
Cash distributions paid to noncontrolling interests:			
Limited partners of Oiltanking other than EPO	$ --	$ --	$ 8.1
Joint venture partners	49.2	47.4	39.9
Total	$ 49.2	$ 47.4	$ 48.0
Cash contributions from noncontrolling interests:			
Joint venture partners	$ 0.4	$ 20.4	$ 54.0

Cash Distributions

The following table presents Enterprise's declared quarterly cash distribution rates per common unit with respect to the quarter indicated. Actual cash distributions are paid by Enterprise within 45 days after the end of each fiscal quarter.

	Distribution Per Common Unit	Record Date	Payment Date
2015:			
1st Quarter	$ 0.3750	4/30/2015	5/7/2015
2nd Quarter	$ 0.3800	7/31/2015	8/7/2015
3rd Quarter	$ 0.3850	10/30/2015	11/6/2015
4th Quarter	$ 0.3900	1/29/2016	2/5/2016
2016:			
1st Quarter	$ 0.3950	4/29/2016	5/6/2016
2nd Quarter	$ 0.4000	7/29/2016	8/5/2016
3rd Quarter	$ 0.4050	10/31/2016	11/7/2016
4th Quarter	$ 0.4100	1/31/2017	2/7/2017
2017:			
1st Quarter	$ 0.4150	4/28/2017	5/8/2017
2nd Quarter	$ 0.4200	7/31/2017	8/7/2017
3rd Quarter	$ 0.4225	10/31/2017	11/7/2017
4th Quarter	$ 0.4250	1/31/2018	2/7/2018

In October 2017, management announced plans to recommend to the Board cash distribution increases per quarter of $0.0025 per unit with respect to each of the six fiscal quarters beginning with the third quarter of 2017 and ending with the fourth quarter of 2018. Management currently expects to recommend to the Board the following quarterly cash distributions with respect to each quarter of 2018: $0.4275, first quarter of 2018; $0.4300, second quarter of 2018; $0.4325, third quarter of 2018; and $0.4350, fourth quarter of 2018.

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

In November 2010, we completed our merger with Enterprise GP Holdings L.P. (the "Holdings Merger"). In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular cash distributions it would otherwise receive from us with respect to a certain number of our common units it owns (the "Designated Units"). Distributions paid by us to this privately held affiliate of EPCO during calendar year 2015 excluded 35,380,000 Designated Units. The temporary distribution waiver expired in November 2015; therefore, distributions paid during calendar years 2016 and 2017 were paid on all outstanding common units.

Note 10. Business Segments and Related Information

Segment Overview

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. The Chief Executive Officer and President of our general partner have been identified as our chief operating decision makers. While these two officers evaluate results in a number of different ways, the business segment structure is the primary basis for which the allocation of resources and financial results are assessed.

The following information summarizes the current assets and operations of each business segment (mileage and other statistics are unaudited):

- Our NGL Pipelines & Services business segment includes our natural gas processing plants and associated NGL marketing activities; approximately 19,600 miles of NGL pipelines; NGL and related product storage facilities; and 14 NGL fractionators. This segment also includes our NGL export docks and related operations.

- Our Crude Oil Pipelines & Services business segment includes approximately 5,800 miles of crude oil pipelines, crude oil storage terminals located in Oklahoma and Texas, and associated crude oil marketing activities.

- Our Natural Gas Pipelines & Services business segment includes approximately 19,700 miles of natural gas pipeline systems that provide for the gathering and transportation of natural gas in Colorado, Louisiana, New Mexico, Texas and Wyoming. This segment also includes our natural gas marketing activities.

- Our Petrochemical & Refined Products Services business segment includes (i) propylene production facilities, which include our propylene fractionation units and recently completed PDH facility, approximately 800 miles of pipelines, and associated marketing operations; (ii) a butane isomerization complex and related deisobutanizer units; (iii) octane enhancement and high purity isobutylene production facilities; (iv) refined products pipelines aggregating approximately 4,100 miles, terminals and associated marketing activities; and (v) marine transportation.

Our plants, pipelines and other fixed assets are located in the U.S.

Sale of Offshore Business

In July 2015, we completed the sale of our Offshore Business, which comprised our Offshore Pipelines & Services business segment, to Genesis for approximately $1.53 billion in cash. Our Offshore Business served drilling and development regions, including deepwater production fields, in the northern Gulf of Mexico offshore Alabama, Louisiana, Mississippi and Texas and included approximately 2,350 miles of offshore natural gas and crude oil pipelines and six offshore hub platforms.

We viewed our Offshore Business as an extension of our midstream energy services network. As such, the sale of these assets did not represent a strategic shift in our consolidated operations, and their sale did not have a major effect on our financial results. The sale of this non-strategic business allowed us to redeploy capital to other business opportunities that we believe will generate a higher rate of return for us in the future (e.g., our acquisition of EFS Midstream – see Note 12).

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 Year Ended December 31,		
	2017	2016	2015
Income before income taxes	$ 2,881.3	$ 2,576.4	$ 2,555.9
Add total other expense, net	1,047.6	1,004.3	984.3
Operating income	3,928.9	3,580.7	3,540.2
Adjustments to reconcile operating income to total gross operating margin:			
Add depreciation, amortization and accretion expense in operating costs and expenses	1,531.3	1,456.7	1,428.2
Add asset impairment and related charges in operating costs and expenses	49.8	52.8	162.6
Add net losses or subtract net gains attributable to asset sales in operating costs and expenses	(10.7)	(2.5)	15.6
Add general and administrative costs	181.1	160.1	192.6
Adjustments for make-up rights on certain new pipeline projects:			
Add non-refundable payments received from shippers attributable to make-up rights (1)	24.1	17.5	53.6
Subtract the subsequent recognition of revenues attributable to make-up rights (2)	(29.9)	(34.6)	(60.7)
Total segment gross operating margin	$ 5,674.6	$ 5,230.7	$ 5,332.1

(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.

The results of operations from our liquids pipelines are primarily dependent upon the volumes transported and the associated fees we charge for such transportation services. Typically, pipeline transportation revenue is recognized when volumes are re-delivered to customers. However, under certain pipeline transportation agreements, customers are required to ship a minimum volume over an agreed-upon period. These arrangements may entail the shipper paying a transportation fee based on a minimum volume commitment, with a provision that allows the shipper to make-up any volume shortfalls over the agreed-upon period (referred to as shipper “make-up rights”). Revenue pursuant to such agreements, including that associated with make-up rights, is initially deferred and subsequently recognized under GAAP at the earlier of when the deficiency volume is shipped, when the shipper’s ability to meet the minimum volume commitment has expired (typically a one year contractual period), or when the pipeline is otherwise released from its transportation service performance obligation.

However, management includes deferred transportation revenues relating to the “make-up rights” of committed shippers when reviewing the financial results of certain new pipeline projects (Texas Express Pipeline, Front Range Pipeline, ATEX, Aegis Ethane Pipeline and Seaway Pipeline). From an internal (and segment) reporting standpoint, management considers the transportation fees paid by committed shippers on these pipeline projects, including any non-refundable revenues that may be deferred under GAAP related to make-up rights, to be important in assessing the financial performance of these pipeline assets. Although the adjustments for make-up rights are included in segment gross operating margin, our consolidated revenues do not reflect any deferred revenues until the conditions for recognizing such revenues are met in accordance with GAAP.

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 Year Ended December 31,		
	2017	2016	2015
Gross operating margin by segment:			
NGL Pipelines & Services	$ 3,258.3	$ 2,990.6	$ 2,771.6
Crude Oil Pipelines & Services	987.2	854.6	961.9
Natural Gas Pipelines & Services	714.5	734.9	782.6
Petrochemical & Refined Products Services	714.6	650.6	718.5
Offshore Pipelines & Services	--	--	97.5
Total segment gross operating margin	$ 5,674.6	$ 5,230.7	$ 5,332.1

Summarized Segment Financial Information

Information by business segment, together with reconciliations to amounts presented on our 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	Offshore Pipelines & Services	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:							
Year ended December 31, 2017	$ 12,455.7	$ 8,137.2	$ 3,132.5	$ 5,471.1	$ --	$ --	$ 29,196.5
Year ended December 31, 2016	10,232.7	6,478.7	2,532.4	3,721.8	--	--	22,965.6
Year ended December 31, 2015	9,779.0	10,258.3	2,729.5	4,111.9	76.9	--	26,955.6
Revenues from related parties:							
Year ended December 31, 2017	12.3	19.6	13.1	--	--	--	45.0
Year ended December 31, 2016	9.8	36.3	10.6	--	--	--	56.7
Year ended December 31, 2015	9.0	47.6	13.8	--	1.9	--	72.3
Intersegment and intrasegment revenues:							
Year ended December 31, 2017	27,278.6	15,943.0	850.8	1,766.9	--	(45,839.3)	--
Year ended December 31, 2016	19,150.0	9,052.0	668.5	1,234.8	--	(30,105.3)	--
Year ended December 31, 2015	10,217.9	5,162.0	662.1	1,126.0	0.6	(17,168.6)	--
Total revenues:							
Year ended December 31, 2017	39,746.6	24,099.8	3,996.4	7,238.0	--	(45,839.3)	29,241.5
Year ended December 31, 2016	29,392.5	15,567.0	3,211.5	4,956.6	--	(30,105.3)	23,022.3
Year ended December 31, 2015	20,005.9	15,467.9	3,405.4	5,237.9	79.4	(17,168.6)	27,027.9
Equity in income (loss) of unconsolidated affiliates:							
Year ended December 31, 2017	73.4	358.4	3.8	(9.6)	--	--	426.0
Year ended December 31, 2016	61.4	311.9	3.8	(15.1)	--	--	362.0
Year ended December 31, 2015	57.5	281.4	3.8	(15.7)	46.6	--	373.6

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

We include equity in income of unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Equity investments with industry partners are a significant component of our business strategy. They are a means by which we conduct our operations to align our interests with those of customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed. Many of these businesses perform supporting or complementary roles to our other midstream business operations.

Our integrated midstream energy asset network (including the midstream energy assets owned by our equity method investees) provides services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. In general, hydrocarbons may enter our asset system in a number of ways, such as through a natural gas processing plant, a natural gas gathering pipeline, a crude oil pipeline or terminal, an NGL fractionator, an NGL storage facility or an NGL gathering or transportation pipeline. Many of our equity investees are included within our integrated midstream asset network. For example, we use the Front Range Pipeline and Texas Express Pipeline to transport mixed NGLs to our Mont Belvieu complex for fractionation and storage and the Seaway Pipeline to transport crude oil to our terminals in the Houston, Texas area. Given the integral nature of our equity method investees to our operations, we believe the presentation of equity earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Information by business segment, together with reconciliations to our 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**	**Offshore Pipelines & Services**	**Adjustments and Eliminations**	**Consolidated Total**
Property, plant and equipment, net: (see Note 5)							
At December 31, 2017	$ 13,831.2	$ 5,208.4	$ 8,375.0	$ 3,507.7	$ --	$ 4,698.1	$ 35,620.4
At December 31, 2016	14,091.5	4,216.1	8,403.0	3,261.2	--	3,320.7	33,292.5
At December 31, 2015	12,909.7	3,550.3	8,620.0	3,060.7	--	3,894.0	32,034.7
Investments in unconsolidated affiliates: (see Note 6)							
At December 31, 2017	733.9	1,839.2	20.8	65.5	--	--	2,659.4
At December 31, 2016	750.4	1,824.6	21.7	80.6	--	--	2,677.3
At December 31, 2015	718.7	1,813.4	22.5	73.9	--	--	2,628.5
Intangible assets, net: (see Note 7)							
At December 31, 2017	322.3	2,186.5	1,018.4	163.1	--	--	3,690.3
At December 31, 2016	350.2	2,279.0	1,054.5	180.4	--	--	3,864.1
At December 31, 2015	380.3	2,377.5	1,087.7	191.7	--	--	4,037.2
Goodwill: (see Note 7)							
At December 31, 2017	2,651.7	1,841.0	296.3	956.2	--	--	5,745.2
At December 31, 2016	2,651.7	1,841.0	296.3	956.2	--	--	5,745.2
At December 31, 2015	2,651.7	1,841.0	296.3	956.2	--	--	5,745.2
Segment assets:							
At December 31, 2017	17,539.1	11,075.1	9,710.5	4,692.5	--	4,698.1	47,715.3
At December 31, 2016	17,843.8	10,160.7	9,775.5	4,478.4	--	3,320.7	45,579.1
At December 31, 2015	16,660.4	9,582.2	10,026.5	4,282.5	--	3,894.0	44,445.6

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 supplemental information regarding our consolidated revenues and costs and expenses for the periods indicated:

	For the Year Ended December 31,		
	2017	2016	2015
Consolidated revenues:			
NGL Pipelines & Services	$ 12,468.0	$ 10,242.5	$ 9,788.0
Crude Oil Pipelines & Services	8,156.8	6,515.0	10,305.9
Natural Gas Pipelines & Services	3,145.6	2,543.0	2,743.3
Petrochemical & Refined Products Services	5,471.1	3,721.8	4,111.9
Offshore Pipelines & Services	--	--	78.8
Total consolidated revenues	$ 29,241.5	$ 23,022.3	$ 27,027.9
Consolidated costs and expenses:			
Operating costs and expenses:			
Cost of sales	$ 21,487.0	$ 15,710.9	$ 19,612.9
Other operating costs and expenses (1)	2,500.1	2,425.6	2,449.4
Depreciation, amortization and accretion	1,531.3	1,456.7	1,428.2
Asset impairment and related charges	49.8	52.8	162.6
Net losses (gains) attributable to asset sales	(10.7)	(2.5)	15.6
General and administrative costs	181.1	160.1	192.6
Total consolidated costs and expenses	$ 25,738.6	$ 19,803.6	$ 23,861.3

(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 and insurance recoveries.

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

Major Customer Information

Our largest non-affiliated customer for 2017 was Vitol Holding B.V. and its affiliates (collectively, "Vitol"), which accounted for \$3.29 billion, or 11.2%, of our consolidated revenues for the year. Vitol is a global energy and commodity trading company. The following table presents our consolidated revenues from Vitol by business segment for the year ended December 31, 2017:

NGL Pipelines & Services	$ 2,099.1
Crude Oil Pipelines & Services	625.6
Natural Gas Pipelines & Services	51.1
Petrochemical & Refined Products Services	512.5
Total	$ 3,288.3

Vitol was our largest non-affiliated customer for 2016, accounting for 9.9% of our consolidated revenues. Shell Oil Company and its affiliates was our largest non-affiliated customer for 2015, accounting for 7.4%, of our consolidated revenues.

Note 11. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss available to our common unitholders by the weighted-average number of our distribution-bearing units outstanding during a period, which excluded the Designated Units (see Note 9) to the extent such units did not participate in the distributions to be paid with respect to such period.

Diluted earnings per unit is computed by dividing net income or loss attributable to our limited partners by the sum of (i) the weighted-average number of our distribution-bearing units outstanding during a period (as used in determining basic earnings per unit), (ii) the weighted-average number of Designated Units outstanding during a period and (iii) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net losses, the Designated Units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase common units at an average market price during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

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

	For the Year Ended December 31,		
	2017	2016	2015
BASIC EARNINGS PER UNIT			
Net income attributable to limited partners	$ 2,799.3	$ 2,513.1	$ 2,521.2
Undistributed earnings allocated and cash payments on phantom unit awards (1)	(15.9)	(12.9)	(8.7)
Net income available to common unitholders	$ 2,783.4	$ 2,500.2	$ 2,512.5
Basic weighted-average number of common units outstanding	2,145.0	2,081.4	1,966.6
Basic earnings per unit	$ 1.30	$ 1.20	$ 1.28
DILUTED EARNINGS PER UNIT			
Net income attributable to limited partners	$ 2,799.3	$ 2,513.1	$ 2,521.2
Diluted weighted-average number of units outstanding:			
Distribution-bearing common units	2,145.0	2,081.4	1,966.6
Designated Units	--	--	26.5
Phantom units (1)	9.3	7.7	5.4
Incremental option units	--	--	0.1
Total	2,154.3	2,089.1	1,998.6
Diluted earnings per unit	$ 1.30	$ 1.20	$ 1.26

(1) Each phantom unit award includes a DER, which entitles the recipient to receive cash payments equal to the product of the number of phantom unit awards and the cash distribution per unit paid to our common unitholders. Cash payments made in connection with DERs are nonforfeitable. As a result, the phantom units are considered participating securities for purposes of computing basic earnings per unit.

Note 12. Business Combinations

Acquisition of Azure Midstream

In April 2017, we closed the acquisition of a midstream energy business from Azure Midstream Partners, LP and its operating subsidiaries (collectively, "Azure") for $191.4 million in cash. The acquired business assets, which are located primarily in East Texas, include over 750 miles of natural gas gathering pipelines and two natural gas processing facilities (Panola and Fairway) with an aggregate processing capacity of 130 MMcf/d. The acquired business primarily serves production from the Haynesville Shale and Bossier, Cotton Valley and Travis Peak formations.

The financial results of the acquired business are reflected in our consolidated results from April 30, 2017, which was the effective date of the Azure acquisition. On a historical pro forma consolidated basis, our revenues, costs and expenses, operating income, net income attributable to Enterprise Products Partners L.P., and earnings per unit amounts for the years ended December 31, 2017 and 2016 would not have differed materially from those we actually reported had the Azure acquisition been completed on January 1, 2016 rather than April 30, 2017.

The following table presents the final fair value allocation of assets acquired and liabilities assumed in the Azure acquisition at April 30, 2017.

Assets acquired in business combination:	
Current assets	$ 3.1
Property, plant and equipment	193.1
Total assets acquired	196.2
Liabilities assumed in business combination:	
Current liabilities	1.4
Long-term liabilities	3.4
Total liabilities assumed	4.8
Cash used for Azure acquisition	$ 191.4

The contribution of this newly acquired business to our consolidated revenues and net income was not material for the year ended December 31, 2017.

Acquisition of EFS Midstream

In July 2015, we purchased EFS Midstream from affiliates of PXD and Reliance for approximately $2.1 billion, which was payable in two installments. The initial payment of $1.1 billion was paid at closing on July 8, 2015. The second and final installment of $1.0 billion was paid on July 11, 2016 using a combination of cash on hand and proceeds from the issuance of short-term notes under EPO's commercial paper program.

The EFS Midstream System provides condensate gathering and processing services as well as gathering, treating and compression services for the associated natural gas. Our primary purpose in acquiring the EFS Midstream System was to secure the underlying production, particularly the processed condensate, for our midstream asset network. Under terms of the associated agreements, PXD and Reliance dedicated certain of their Eagle Ford Shale acreage to us under 20-year, fixed-fee gathering agreements that include minimum volume requirements for the first seven years. PXD and Reliance also entered into related 20-year fee-based agreements with us for natural gas transportation and processing, NGL transportation and fractionation, and for processed condensate and crude oil transportation services.

In connection with the agreements to acquire EFS Midstream, we are obligated to spend up to an aggregate of $270 million on specified midstream gathering assets for PXD and Reliance, if requested by these producers, over a ten-year period. If constructed, these new assets would be owned by us and be a component of the EFS Midstream System.

Since the effective date of the EFS Midstream acquisition was July 1, 2015, our Statements of Consolidated Operations do not reflect any earnings from this business prior to this date. Our consolidated revenues and net income for the last six months ended December 31, 2015 include $117.8 million and $59.9 million, respectively, from EFS Midstream. The following table presents selected unaudited pro forma earnings information for the year ended December 31, 2015 as if the acquisition had been completed on January 1, 2015. This pro forma information was prepared using historical financial data for EFS Midstream and reflects certain estimates and assumptions made by our management. Our unaudited pro forma financial information is not necessarily indicative of what our consolidated financial results would have been for the year ended December 31, 2015 had we acquired EFS Midstream on January 1, 2015.

Pro forma earnings data:		
Revenues	$	27,148.5
Costs and expenses		23,937.1
Operating income		3,585.0
Net income		2,594.4
Net income attributable to noncontrolling interests		37.2
Net income attributable to limited partners		2,557.2
Basic earnings per unit:		
As reported basic earnings per unit	$	1.28
Pro forma basic earnings per unit	$	1.30
Diluted earnings per unit:		
As reported diluted earnings per unit	$	1.26
Pro forma diluted earnings per unit	$	1.28

Acquisition of Oiltanking

On October 1, 2014, we acquired Oiltanking GP and the related IDRs, 15,899,802 common units and 38,899,802 subordinated units of Oiltanking from OTA. We paid total consideration of approximately $4.4 billion to OTA comprised of $2.21 billion in cash and 54,807,352 Enterprise common units for these ownership interests and rights. We also paid $228.3 million to assume the outstanding loans, including related accrued interest, owed by Oiltanking or its subsidiaries to OTA. Collectively, these transactions are referred to as "Step 1" of the Oiltanking acquisition. We funded the cash consideration for the Step 1 transactions using borrowings under our 364-Day Credit Agreement, proceeds from the sale of short-term notes under our commercial paper program and cash on hand.

Oiltanking owned marine terminals located on the Houston Ship Channel and at the Port of Beaumont featuring a number of ship and barge docks and extensive crude oil and petroleum products storage capacity. We had a strategic relationship and enjoyed mutual growth with Oiltanking and its predecessors since 1983. The combination of our legacy midstream assets and Oiltanking's access to waterborne markets and crude oil and petroleum products storage assets extended and broadened our midstream energy services business.

Step 2 of the Oiltanking acquisition. As a second step ("Step 2") of the Oiltanking acquisition (separately negotiated by the conflicts committee of Oiltanking GP on behalf of Oiltanking), we entered into an Agreement and Plan of Merger (the "merger agreement") with Oiltanking in November 2014 that provided for the following:

- the merger of a wholly owned subsidiary of ours with and into Oiltanking, with Oiltanking surviving the merger as our wholly owned subsidiary; and

- all outstanding common units of Oiltanking at the effective time of the merger held by Oiltanking's public unitholders (which consisted of Oiltanking unitholders other than us and our subsidiaries) to be cancelled and converted into our common units based on an exchange ratio of 1.30 of our common units for each Oiltanking common unit.

In accordance with the merger agreement and Oiltanking's partnership agreement, the merger was submitted to a vote of Oiltanking's common unitholders, with the required majority of unitholders (including our ownership interests) voting to approve the merger on February 13, 2015. Upon approval of the merger, a total of 36,827,517 of our common units were issued to Oiltanking's former public unitholders. With the completion of Step 2, total consideration paid by Enterprise for Oiltanking was approximately $6.02 billion.

Since we had a controlling financial interest in Oiltanking before and after completion of Step 2, the increase in our ownership interest in Oiltanking was accounted for as an equity transaction with no gain or loss recognized. Step 2 represented our acquisition of the noncontrolling interests in Oiltanking; therefore, approximately $1.4 billion of noncontrolling interests attributable to Oiltanking were reclassified to limited partners' equity to reflect the February 2015 issuance of 36,827,517 new common units.

Upon completion of the merger, the IDRs of Oiltanking were cancelled since we now own 100% of the future cash flows attributable to the Oiltanking business we acquired. As a result, the $1.46 billion carrying value of the IDR intangible asset was reclassified to goodwill and allocated among our business segments (see Note 7).

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 Year Ended December 31,		
	2017	2016	2015
Equity-classified awards:			
Phantom unit awards	$ 92.8	$ 78.6	$ 78.3
Restricted common unit awards	0.5	4.7	14.7
Profits interest awards	6.0	5.4	--
Liability-classified awards	0.4	0.5	0.2
Total	$ 99.7	$ 89.2	$ 93.2

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 December 31, 2017, all of the phantom unit awards were granted under EPCO's 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) ("2008 Plan"). The 2008 Plan is a long-term incentive plan under which any employee or consultant of EPCO, us or our affiliates that provides services to us, directly or indirectly, may receive incentive compensation awards in the form of options, restricted common units, phantom units, distribution equivalent rights ("DERs"), unit appreciation rights ("UARs"), unit awards, other unit-based awards or substitute awards. Non-employee directors of our general partner may also participate in the 2008 Plan. The maximum number of common units authorized for issuance under the 2008 Plan was 40,000,000 at December 31, 2017. This amount automatically increased under the terms of the 2008 Plan by 5,000,000 common units on January 1, 2018 and will continue to automatically increase annually on 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. The 2008 Plan is effective until September 30, 2023 or, if earlier, until the time that all available common units under the 2008 Plan have been delivered to participants or the time of termination of the 2008 Plan by the Board of Directors of EPCO or by the Audit and Conflicts Committee. After giving effect to awards granted under the 2008 Plan through December 31, 2017, a total of 19,091,065 additional common units were available for issuance.

During 2016, EPCO formed four limited partnerships (generally referred to as "Employee Partnerships") to serve as long-term 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"). The Employee Partnerships are discussed later in this note.

At December 31, 2017, there were no restricted common unit awards outstanding under the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan"). The 1998 Plan is effectively closed and no new awards have been granted under this plan since 2014. The 1998 Plan provided for awards of our common units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Historically, awards under the 1998 Plan consisted of unit options and restricted common units.

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. All of the phantom unit awards were issued under the 2008 Plan.

At December 31, 2017, substantially all of our phantom unit awards are expected to result in the issuance of common units upon vesting; therefore, the applicable awards are accounted for as equity-classified awards. The grant date fair value of a phantom unit award is based on the market price per unit of our common units on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

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

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Phantom unit awards at January 1, 2015	3,342,390	$ 33.13
Granted (2)	3,496,140	$ 33.96
Vested	(940,415)	$ 33.14
Forfeited	(471,166)	$ 33.51
Phantom unit awards at December 31, 2015	5,426,949	$ 33.63
Granted (3)	4,508,310	$ 21.90
Vested	(1,761,455)	$ 33.10
Forfeited	(406,303)	$ 28.52
Phantom unit awards at December 31, 2016	7,767,501	$ 27.20
Granted (4)	4,268,920	$ 28.83
Vested	(2,490,081)	$ 28.30
Forfeited	(256,839)	$ 27.60
Phantom unit awards at December 31, 2017	9,289,501	$ 27.65

(1) Determined by dividing the aggregate grant date fair value of awards (before an allowance for forfeitures) by the number of awards issued.
(2) The aggregate grant date fair value of phantom unit awards issued during 2015 was $118.7 million based on a grant date market price of our common units ranging from $27.31 to $34.40 per unit. An estimated annual forfeiture rate of 3.5 percent was applied to these awards.
(3) The aggregate grant date fair value of phantom unit awards issued during 2016 was $98.7 million based on a grant date market price of our common units ranging from $21.86 to $27.39 per unit. An estimated annual forfeiture rate of 3.9 percent was applied to these awards.
(4) The aggregate grant date fair value of phantom unit awards issued during 2017 was $123.1 million based on a grant date market price of our common units ranging from $24.55 to $28.87 per unit. An estimated annual forfeiture rate of 3.8 percent was applied to these awards.

After taking into account tax withholding requirements, we issued 1,687,692, 1,170,600 and 618,395 common units in connection with the vesting of phantom unit awards in the years ended December 31, 2017, 2016 and 2015, respectively.

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 Year Ended December 31,		
	2017	2016	2015
Cash payments made in connection with DERs	$ 15.1	$ 11.7	$ 7.7
Total intrinsic value of phantom unit awards that vested during period	$ 69.8	$ 40.9	$ 31.2

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was $92.3 million at December 31, 2017, of which our share of the cost is currently estimated to be $77.5 million. Due to the graded vesting provisions of these awards, we expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.1 years.

Profits Interest Awards

In February and April 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 as disclosed in the table below. 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.

In general, the Class A limited partner earns a quarterly preferred return equal to $0.39 per unit on the number of Enterprise common units contributed by EPCO Holdings to each Employee Partnership, with any residual cash amount remaining in each Employee Partnership being paid to the applicable Class B limited partners on a quarterly basis as a distribution. Upon liquidation of an Employee Partnership, assets having a then current fair market value equal to the Class A limited partner's capital base in such Employee Partnership will be distributed to the Class A limited partner. Any remaining assets of such Employee Partnership will be distributed to the Class B limited partners of such Employee Partnership as a residual profits interest, which represents the appreciation in value of the Employee Partnership's assets since the date of EPCO Holdings' contribution to it, as described above.

Unless otherwise agreed to by EPCO and a majority in interest of the limited partners of each Employee Partnership, such Employee Partnership will terminate at the earliest to occur of (i) 30 days following its vesting date, (ii) a change of control or (iii) a dissolution of the Employee Partnership.

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

The following table summarizes key elements of each Employee Partnership as of December 31, 2017:

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	$13.2 million	$7.4 million
PubCo II	2,834,198	$66.3 million	$0.39	Feb. 2021	$14.7 million	$9.3 million
PubCo III	105,000	$2.5 million	$0.39	Apr. 2020	$0.6 million	$0.2 million
PrivCo I	1,111,438	$26.0 million	$0.39	Feb. 2021	$5.8 million	$0.8 million

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

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

(3) Represents the total grant date fair value of the profits interest awards 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 December 31, 2017. We expect to recognize our share of the unrecognized compensation cost for PubCo I, PubCo II, PubCo III and PrivCo I over a weighted-average period of 2.1 years, 3.1 years, 2.3 years and 3.1 years, respectively.

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

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

Employee Partnership	Expected Life of Award	Risk-Free Interest Rate	Expected Distribution Yield	Expected Unit Price Volatility
PubCo I	4.0 years	0.9% to 1.6%	6.2% to 7.0%	29% to 40%
PubCo II	5.0 years	1.1% to 1.8%	6.1% to 7.0%	27% to 40%
PubCo III	4.0 years	1.0% to 1.4%	6.1% to 6.2%	31% to 40%
PrivCo I	5.0 years	1.2% to 1.6%	6.1% to 6.7%	28% to 40%

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

Restricted Common Unit Awards

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

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

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

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted common units at January 1, 2015	4,229,790	$ 26.96
Vested	(2,009,970)	$ 26.00
Forfeited	(259,300)	$ 27.53
Restricted common units at December 31, 2015	1,960,520	$ 27.88
Vested	(1,234,502)	$ 27.45
Forfeited	(43,724)	$ 28.48
Restricted common units at December 31, 2016	682,294	$ 28.61
Vested	(681,044)	$ 28.60
Forfeited	(1,250)	$ 31.07
Restricted common units at December 31, 2017	--	N/A

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

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

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

	For the Year Ended December 31,		
	2017	2016	2015
Cash distributions paid to restricted common unitholders	$ 0.3	$ 1.6	$ 4.0
Total intrinsic value of restricted common unit awards that vested during period	$ 18.9	$ 28.5	$ 67.3

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options denominated in our common units. Historically, our unit option awards were issued under the 1998 Plan. All such awards had been exercised as of December 31, 2015 and no new unit option awards were granted during the three years ended December 31, 2017.

When issued, the exercise price of each unit option award was equal to the market price of our common units on the date of grant. In general, unit option awards had a vesting period of four years from the date of grant and expired at the end of the calendar year following the year of vesting. The fair value of each unit option award was estimated on the date of grant using a Black-Scholes option pricing model, which incorporated various assumptions including expected life of the option, risk-free interest rates, expected distribution yield of our common units, and expected price volatility of our common units. Compensation expense recorded in connection with unit option awards was 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 unit option award activity for the period indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)
Unit option awards at January 1, 2015	1,270,000	$ 16.14
Exercised	(1,270,000)	$ 16.14
Unit option awards at December 31, 2015	--	$ --

In order to fund its unit option award-related obligations, EPCO purchased our common units at fair value directly from us. When employees exercised unit option awards, we reimbursed EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The following table presents supplemental information regarding unit option awards during the year ended December 31, 2015:

Total intrinsic value of unit option awards exercised during period	$ 21.7
Cash received from EPCO in connection with the exercise of unit option awards	$ 13.1
Unit option award-related cash reimbursements to EPCO	$ 21.7

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.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy may be used in controlling our overall cost of capital associated with such borrowings.

The following table summarizes our portfolio of interest rate swaps at December 31, 2017:

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes OO	10 fixed-to-floating swaps	$750.0	5/2015 to 5/2018	1.65% to 1.87%	Fair value hedge

At December 31, 2017, our portfolio of forward starting swaps was as follows:

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

As a result of market conditions in 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 gains totaling $1.5 million for the first quarter of 2018.

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

As a result of market conditions in October 2016, we elected to terminate forward starting swaps that were scheduled to settle in September 2017, which resulted in cash gains totaling $6.1 million. As cash flow hedges, gains on these derivative instruments will be reflected as a component of accumulated other comprehensive income and be amortized to earnings (as a decrease in interest expense) over the life of the associated future debt obligations beginning in September 2017.

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 December 31, 2017, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging natural gas processing margins and (iii) hedging the fair value of commodity products held in inventory.

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

- The objective of our natural gas processing hedging program is to hedge an amount of earnings associated with these activities. We achieve this objective by executing fixed-price sales for a portion of our expected equity NGL production using derivative instruments and related contracts. For certain natural gas processing contracts, the hedging of expected equity NGL production also involves the purchase of natural gas for 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 summarizes our portfolio of commodity derivative instruments outstanding at December 31, 2017 (volume measures as noted):

	Volume (1)		Accounting
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Octane enhancement:			
Forecasted purchase of NGLs (MMBbls)	1.1	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	1.0	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	1.0	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	3.9	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	49.0	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	64.6	n/a	Cash flow hedge
NGLs inventory management activities (MMBbls)	0.5	n/a	Fair value hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.6	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.3	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.5	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	3.7	3.3	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	6.9	3.3	Cash flow hedge
Petrochemical marketing:			
Forecasted purchases of NGLs for propylene marketing activities (MMBbls)	0.8	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	67.3	9.0	Mark-to-market
NGL risk management activities (MMBbls) (4)	18.3	n/a	Mark-to-market
Refined products risk management activities (MMBbls) (4)	0.6	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	104.0	12.2	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, May 2018 and December 2020, respectively.
(3) Current and long-term volumes include 21.1 Bcf and 5.3 Bcf, respectively, of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
(4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

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

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			
	December 31, 2017		December 31, 2016		December 31, 2017		December 31, 2016	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments								
Interest rate derivatives	Current assets	$ --	Current assets	$ 0.3	Current liabilities	$ 1.5	Current liabilities	$ 0.2
Interest rate derivatives	Other assets	0.1	Other assets	36.2	Other liabilities	0.2	Other liabilities	0.9
Total interest rate derivatives		0.1		36.5		1.7		1.1
Commodity derivatives	Current assets	109.5	Current assets	499.2	Current liabilities	104.4	Current liabilities	662.0
Commodity derivatives	Other assets	6.4	Other assets	--	Other liabilities	6.8	Other liabilities	--
Total commodity derivatives		115.9		499.2		111.2		662.0
Total derivatives designated as hedging instruments		$ 116.0		$ 535.7		$ 112.9		$ 663.1
Derivatives not designated as hedging instruments								
Commodity derivatives	Current assets	$ 43.9	Current assets	$ 41.9	Current liabilities	$ 62.3	Current liabilities	$ 75.5
Commodity derivatives	Other assets	1.9	Other assets	0.3	Other liabilities	3.4	Other liabilities	1.9
Total commodity derivatives		45.8		42.2		65.7		77.4
Total derivatives not designated as hedging instruments		$ 45.8		$ 42.2		$ 65.7		$ 77.4

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

	Offsetting of Financial Assets and Derivative Assets						
				Gross Amounts Not Offset in the Balance Sheet			
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Financial Instruments	Cash Collateral Paid	Cash Collateral Received	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)		(iv)		(v) = (iii) + (iv)
As of December 31, 2017:							
Interest rate derivatives	$ 0.1	$ --	$ 0.1	$ (0.1)	$ --	$ --	$ --
Commodity derivatives	161.7	--	161.7	(157.8)	--	--	3.9
As of December 31, 2016:							
Interest rate derivatives	$ 36.5	$ --	$ 36.5	$ (0.2)	$ --	$ --	$ 36.3
Commodity derivatives	541.4	--	541.4	(526.8)	--	--	14.6

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

Derivative assets and liabilities recorded on our Consolidated Balance Sheets are presented on a gross-basis and determined at the individual transaction level. This presentation method is applied regardless of whether the respective exchange clearing agreements, counterparty contracts or master netting agreements contain netting language often referred to as “rights of offset.” Although derivative amounts are presented on a gross-basis, having rights of offset enable the settlement of a net as opposed to gross receivable or payable amount under a counterparty default or liquidation scenario.

Cash is paid and received as collateral under certain agreements, particularly for those associated with exchange transactions. For any cash collateral payments or receipts, corresponding assets or liabilities are recorded to reflect the variation margin deposits or receipts with exchange clearing brokers and customers. These balances are also presented on a gross-basis on our Consolidated Balance Sheets.

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 Statements of Consolidated Operations for the periods indicated:

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative		
		For the Year Ended December 31,		
		2017	2016	2015
Interest rate derivatives	Interest expense	$ (0.2)	$ 0.3	$ (1.4)
Commodity derivatives	Revenue	1.1	(90.5)	19.1
Total		$ 0.9	$ (90.2)	$ 17.7

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item		
		For the Year Ended December 31,		
		2017	2016	2015
Interest rate derivatives	Interest expense	$ 0.4	$ (0.4)	$ 1.4
Commodity derivatives	Revenue	27.4	125.0	0.2
Total		$ 27.8	$ 124.6	$ 1.6

For the years ended December 31, 2017 and 2016, the net gains of $28.5 million and $34.5 million, respectively, recognized in income from our commodity derivatives designated as fair value hedges includes $1.0 million and $1.1 million, respectively, of net gains attributable to hedge ineffectiveness. The remaining $27.5 million and $33.4 million was a net gain that was recognized during the years ended December 31, 2017 and 2016, respectively, and primarily related to prompt-to-forward month price differentials that were excluded from the assessment of hedge effectiveness. Net gains or losses due to ineffectiveness and from those amounts excluded from the assessment of hedge effectiveness were immaterial for all other periods presented.

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

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income (Loss) On Derivative (Effective Portion) For the Year Ended December 31, 2017	2016	2015
Interest rate derivatives	$ (5.7)	$ 42.3	$ --
Commodity derivatives – Revenue (1)	(33.7)	(197.4)	217.6
Commodity derivatives – Operating costs and expenses (1)	(4.8)	3.6	(2.7)
Total	$ (44.2)	$ (151.5)	$ 214.9

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

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) to Income (Effective Portion) For the Year Ended December 31, 2017	2016	2015
Interest rate derivatives	Interest expense	$ (40.4)	$ (37.4)	$ (35.3)
Commodity derivatives	Revenue	(111.6)	(53.6)	231.7
Commodity derivatives	Operating costs and expenses	(0.6)	0.2	(3.5)
Total		$ (152.6)	$ (90.8)	$ 192.9

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion) For the Year Ended December 31, 2017	2016	2015
Commodity derivatives	Revenue	$ --	$ --	$ 4.7
Commodity derivatives	Operating costs and expenses	(1.1)	0.5	0.1
Total		$ (1.1)	$ 0.5	$ 4.8

Over the next twelve months, we expect to reclassify $38.4 million of losses attributable to interest rate derivative instruments from accumulated other comprehensive loss to earnings as an increase in interest expense. Likewise, we expect to reclassify $9.7 million of losses attributable to commodity derivative instruments from accumulated other comprehensive income to earnings, $9.4 million as decrease in revenue and $0.3 million as an increase to operating costs and expenses.

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

Derivatives Not Designated as Hedging Instruments	Location	Gain (Loss) Recognized in Income on Derivative For the Year Ended December 31, 2017	2016	2015
Interest rate derivatives	Interest expense	$ --	$ --	$ --
Commodity derivatives	Revenue	(42.7)	(38.4)	1.0
Commodity derivatives	Operating costs and expenses	0.1	(0.4)	0.1
Total		$ (42.6)	$ (38.8)	$ 1.1

Fair Value Measurements

The following tables set forth, by level within the Level 1, 2 and 3 fair value hierarchy (see Note 2), the carrying values of our financial assets and liabilities at the dates indicated. These assets and liabilities are measured on a recurring basis and are classified based on the lowest level of input used to estimate their fair value. Our assessment of the relative significance of such inputs requires judgment.

The values for commodity derivatives at December 31, 2017 are presented before and after the application of CME Rule 814, which deems that financial instruments cleared by the CME are settled daily in connection with variation margin payments. As a result of this new exchange rule, CME-related derivatives are considered to have no fair value at the balance sheet date for financial reporting purposes; however, the derivatives remain outstanding and subject to future commodity price fluctuations until they are settled in accordance with their contractual terms. The rule change was effective January 1, 2017.

	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	$ --	$ 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	$ --	$ 176.9	$ 335.6	$ 512.5

	December 31, 2016 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets:				
Interest rate derivatives	$ --	$ 36.5	$ --	$ 36.5
Commodity derivatives	84.5	455.2	1.7	541.4
Total	$ 84.5	$ 491.7	$ 1.7	$ 577.9
Financial liabilities:				
Liquidity Option Agreement	$ --	$ --	$ 269.6	$ 269.6
Interest rate derivatives	--	1.1	--	1.1
Commodity derivatives	136.8	602.3	0.3	739.4
Total	$ 136.8	$ 603.4	$ 269.9	$ 1,010.1

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 Year Ended December 31, 2017	2016
Financial asset (liability) balance, net, January 1		$ (268.2)	$ (246.7)
Total gains (losses) included in:			
Net income (1)	Revenue	2.3	2.2
Net income	Other expense, net	(64.3)	(24.5)
Other comprehensive income (loss)	Commodity derivative instruments – changes in fair value of cash flow hedges	0.1	(0.5)
Settlements (1)	Revenue	(2.4)	(0.5)
Transfers out of Level 3 (2)		(0.2)	1.8
Financial liability balance, net, December 31 (2)		$ (332.7)	$ (268.2)

(1) There were $0.1 million of unrealized losses and $1.7 million of unrealized gains included in these amounts for the years ended December 31, 2017 and 2016, respectively.
(2) Transfers out of Level 3 into Level 2 were due to shorter remaining transaction maturities falling inside of the Level 2 range at December 31, 2017 and 2016.

The following tables provide quantitative information regarding our recurring Level 3 fair value measurements for commodity derivatives at the dates indicated:

	Fair Value At December 31, 2017 Financial Assets	Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Crude oil	$ 2.9	$ 1.7	Discounted cash flow	Forward commodity prices	$60.21-$66.05/barrel
Total	$ 2.9	$ 1.7			

	Fair Value At December 31, 2016 Financial Assets	Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Crude oil	$ 1.7	$ 0.3	Discounted cash flow	Forward commodity prices	$51.73-$54.77/barrel
Total	$ 1.7	$ 0.3			

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 December 31, 2017. In general, changes in the price of the underlying commodity increases or decreases the fair value of a commodity derivative depending on whether the derivative was purchased or sold. We generally expect changes in the fair value of our derivative instruments to be offset by corresponding changes in the fair value of our hedged exposures.

The recurring fair value measurement pertaining to the Liquidity Option Agreement is based on a number of Level 3 inputs. See Note 17 for a discussion of this liability.

Nonrecurring Fair Value Measurements

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment (i.e., subject to nonrecurring fair value measurements) when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values.

The following table summarizes our non-cash asset impairment charges for long-lived assets by segment during each of the periods indicated:

	For the Year Ended December 31,		
	2017	2016	2015
NGL Pipelines & Services	$ 11.5	$ 21.0	$ 20.8
Crude Oil Pipelines & Services	10.2	2.3	33.5
Natural Gas Pipelines & Services	14.3	12.3	21.6
Petrochemical & Refined Products Services	1.8	9.6	28.2
Offshore Pipelines & Services	--	--	58.5
Total	$ 37.8	$ 45.2	$ 162.6

As presented in the following tables, our estimated fair values were based on management's expectation of the market values for such assets based on their knowledge and experience in the industry (a Level 3 type measure involving significant unobservable inputs). In many cases, there are no active markets (Level 1) or other similar recent transactions (Level 2) to compare to. Our assumptions used in such analyses are based on the highest and best use of the asset and includes estimated probabilities where multiple cash flow outcomes are possible.

When probability weights are used, the weights are generally obtained from business management personnel having oversight responsibilities for the assets being tested. Key commercial assumptions (e.g., anticipated operating margins, throughput or processing volume growth rates, timing of cash flows, etc.) that represent Level 3 unobservable inputs and test results are reviewed and certified by members of senior management.

The following table presents categories of long-lived assets, primarily property, plant and equipment, that were subject to non-recurring fair value measurements during the year ended December 31, 2017:

		Fair Value Measurements at the End of the Reporting Period Using			
	Carrying Value at December 31, 2017	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Long-lived assets disposed of other than by sale	$ --	$ --	$ --	$ --	$ 16.7
Long-lived assets held and used	1.5	--	--	1.5	15.4
Long-lived assets held for sale	2.5	--	--	2.5	2.5
Long-lived assets disposed of by sale	--	--	--	--	3.2
Total					$ 37.8

Total non-cash asset impairment and related charges during 2017 were $49.8 million, which consisted of $37.8 million of impairment charges attributable to long-lived assets and $12.0 million of impairment charges attributable to the write-down of surplus materials classified as current assets. Impairment charges attributable to long-lived assets were primarily due to the write-down of certain natural gas pipeline laterals and other pipelines in Texas, which accounted for $13.0 million in charges, and for the planned abandonment of certain storage and pipeline assets in Texas, which accounted for an additional $12.4 million in charges.

The following table presents categories of long-lived assets, primarily property, plant and equipment, that were subject to non-recurring fair value measurements during the year ended December 31, 2016:

		Fair Value Measurements at the End of the Reporting Period Using			
	Carrying Value at December 31, 2016	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Long-lived assets disposed of other than by sale	$ --	$ --	$ --	$ --	$ 29.9
Long-lived assets held and used	8.0	8.0	--	--	2.2
Long-lived assets disposed of by sale	--	--	--	--	13.1
Total					$ 45.2

Total non -cash asset impairment and related charges during 2016 were $53.5 million, which consisted of $45.2 million of impairment charges attributable to long-lived assets, $1.2 million of impairment charges attributable to the write-down of surplus materials classified as current assets, and $7.1 million of related charges for equipment destroyed by fire at our Pascagoula gas plant. Impairment charges attributable to long-lived assets primarily relate to the planned abandonment of certain plant and pipeline assets in Texas and New Mexico.

Our non-cash asset impairment charges for the year ended December 31, 2015 are a component of operating costs and expenses and primarily reflect the $54.8 million charge we recorded in connection with the sale of our Offshore Business and the abandonment of certain natural gas and crude oil pipeline assets in Texas. The following table presents categories of long-lived assets that were subject to non-recurring fair value measurements during the year ended December 31, 2015:

		Fair Value Measurements at the End of the Reporting Period Using			
	Carrying Value at December 31, 2015	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Long-lived assets disposed of other than by sale	$ 0.4	$ --	$ --	$ 0.4	$ 81.4
Long-lived assets held for sale	18.0	--	--	18.0	14.2
Long-lived assets disposed of by sale	--	--	--	--	67.0
Total					$ 162.6

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 $23.47 billion and $21.95 billion at December 31, 2017 and 2016, respectively. The aggregate carrying value of these debt obligations was $21.48 billion and $20.85 billion at December 31, 2017 and 2016, respectively. These values are primarily based on quoted market prices for such debt or debt of similar terms and maturities (Level 2) and our credit standing. Changes in market rates of interest affect the fair value of our fixed-rate debt. The amounts reported for fixed-rate debt obligations exclude those amounts hedged using fixed-to-floating interest rate swaps. See "*Interest Rate Hedging Activities*" within this Note 14 for additional information.

The carrying values of our variable-rate long-term debt obligations approximate their fair values since the associated interest rates are market-based. We do not have any long-term investments in debt or equity securities recorded at fair value.

Note 15. Related Party Transactions

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

	For the Year Ended December 31,		
	2017	2016	2015
Revenues – related parties:			
Unconsolidated affiliates	$ 45.0	$ 56.7	$ 72.3
Costs and expenses – related parties:			
EPCO and its privately held affiliates	$ 1,010.9	$ 963.2	$ 949.3
Unconsolidated affiliates	223.4	253.9	245.3
Total	$ 1,234.3	$ 1,217.1	$ 1,194.6

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

	December 31,	
	2017	2016
Accounts receivable - related parties:		
Unconsolidated affiliates	$ 1.8	$ 1.1
Accounts payable - related parties:		
EPCO and its privately held affiliates	$ 99.3	$ 88.9
Unconsolidated affiliates	28.0	16.2
Total	$ 127.3	$ 105.1

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

Relationship with EPCO and Affiliates

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

At December 31, 2017, EPCO and its privately held affiliates (including Dan Duncan LLC and certain Duncan family trusts) beneficially owned the following limited partner interests in us:

Total Number of Units	Percentage of Total Units Outstanding
689,767,023	32%

Of the total number of units held by EPCO and its privately held affiliates, 81,346,154 have been pledged as security under the credit facilities of EPCO and its privately held affiliates at December 31, 2017. These credit facilities contain customary and other events of default, including defaults by us and other affiliates of EPCO. An event of default, followed by a foreclosure on the pledged collateral, could ultimately result in a change in ownership of these units and affect the market price of our common units.

We and Enterprise GP are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are also separate from those of EPCO and its other affiliates. EPCO and its privately held affiliates depend on the cash distributions they receive from us and other investments to fund their other activities and to meet their debt obligations. During the years ended December 31, 2017, 2016 and 2015, we paid EPCO and its privately held affiliates cash distributions totaling $1.12 billion, $1.07 billion and $948.3 million, respectively. Distributions paid during the year ended December 31, 2015 excluded 35,380,000 Designated Units (see Note 9).

From time-to-time, EPCO and its privately held affiliates elect to purchase additional common units under our DRIP and our ATM program. In January 2016 and March 2015, privately held affiliates of EPCO purchased 3,830,256 and 3,225,057 common units, respectively, from us under our ATM program, generating gross proceeds of $100 million during each year. In November 2017, privately held affiliates of EPCO reinvested $100 million through our DRIP, resulting in the issuance of an additional 4,246,498 of our common units. For each of the years ended December 31, 2016 and 2015, DRIP purchases by privately held affiliates of EPCO totaled $100 million. See Note 9 for additional information regarding our ATM program and DRIP.

We lease office space from affiliates of EPCO. The rental rates in these lease agreements approximate market rates.

EPCO ASA. 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. We and our general partner are parties to the ASA. The significant terms of the ASA are as follows:

- EPCO will provide selling, general and administrative services and management and operating services as may be necessary to manage and operate our businesses, properties and assets (all in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel.

- We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time with respect to the services provided to us by EPCO.

- EPCO will allow us to participate as a named insured in its overall insurance program, with the associated premiums and other costs being allocated to us. See Note 18 for additional information regarding our insurance programs.

Our operating costs and expenses include amounts paid to EPCO for the costs it incurs to operate our facilities, including the compensation of its employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Likewise, our general and administrative costs include amounts paid to EPCO for administrative services, including the compensation of its employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of legal or accounting salaries based on estimates of time spent on each entity's business and affairs).

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

	For the Year Ended December 31,		
	2017	2016	2015
Operating costs and expenses	$ 882.1	$ 840.7	$ 826.4
General and administrative expenses	110.4	105.3	105.2
Total costs and expenses	$ 992.5	$ 946.0	$ 931.6

Since the vast majority of such expenses are charged to us on an actual basis (i.e., no mark-up is charged or subsidy is received), we believe that such expenses are representative of what the amounts would have been on a standalone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. The following information summarizes significant related party transactions with our current unconsolidated affiliates:

- For the years ended December 31, 2017, 2016 and 2015, we paid Seaway $98.8 million, $161.2 million and $175.8 million, respectively, for pipeline transportation and storage services in connection with our crude oil marketing activities. Revenues from Seaway were $19.6 million, $36.3 million and $47.7 million for the years ended December 31, 2017, 2016 and 2015, respectively.

- We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Revenues from Promix were $7.8 million, $7.0 million and $8.8 million for the years ended December 31, 2017, 2016 and 2015, respectively. Expenses with Promix were $27.8 million, $27.1 million and $24.9 million for the years ended December 31, 2017, 2016 and 2015, respectively.

- For the years ended December 31, 2017, 2016 and 2015, we paid Texas Express $29.5 million, $22.8 million and $6.7 million, respectively, for pipeline transportation services.

- For the years ended December 31, 2017, 2016 and 2015, we paid Eagle Ford Crude Oil Pipeline $42.8 million, $36.2 million and $39.4 million, respectively, for crude oil transportation.

- We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $10.6 million, $10.7 million and $19.1 million for the years ended December 31, 2017, 2016 and 2015, respectively. The decrease in such amounts during 2016 is related to the sale of our Offshore Business.

Note 16. Provision for Income Taxes

Publicly traded partnerships like ours are treated as corporations unless they have 90% or more in "qualifying income" (as that term is defined in the Internal Revenue Code). We satisfied this requirement in each of the years ended December 31, 2017, 2016 and 2015 and, as a result, are not subject to federal income tax. However, our partners are individually responsible for paying federal income tax on their share of our taxable income. Net earnings for financial reporting purposes may differ significantly from taxable income reportable to our unitholders as a result of differences between the tax basis and financial reporting basis of certain assets and liabilities and other factors. We do not have access to information regarding each partner's individual tax basis in our limited partner interests.

Provision for income taxes primarily reflects our state tax obligations under the Revised Texas Franchise Tax (the "Texas Margin Tax"). Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

Our federal, state and foreign income tax provision (benefit) is summarized below:

	For the Year Ended December 31,		
	2017	2016	2015
Current:			
Federal	$ 0.1	$ (0.5)	$ 0.9
State	18.5	16.7	15.5
Foreign	1.0	0.6	1.7
Total current	19.6	16.8	18.1
Deferred:			
Federal	(1.8)	1.1	(1.4)
State	7.9	5.2	(19.2)
Foreign	--	0.3	--
Total deferred	6.1	6.6	(20.6)
Total provision for (benefit from) income taxes	$ 25.7	$ 23.4	$ (2.5)

A reconciliation of the provision for (benefit from) income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income before income taxes is as follows:

	For the Year Ended December 31,		
	2017	2016	2015
Pre-Tax Net Book Income ("NBI")	$ 2,881.3	$ 2,576.4	$ 2,555.9
Texas Margin Tax (1)	$ 26.4	$ 22.1	$ (3.7)
State income taxes (net of federal benefit)	0.5	0.2	0.7
Federal income taxes computed by applying the federal statutory rate to NBI of corporate entities	0.1	0.8	1.1
Other permanent differences	(1.3)	0.3	(0.6)
Provision for (benefit from) income taxes	$ 25.7	$ 23.4	$ (2.5)
Effective income tax rate	0.9%	0.9%	(0.1)%

(1) Although the Texas Margin Tax is not considered a state income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers our Texas-sourced revenues and expenses. During 2015, certain legislative changes were enacted to the Texas Margin Tax, which reduced the tax rate for business entities that operate within the state.

The following table presents the significant components of deferred tax assets and deferred tax liabilities at the dates indicated:

	December 31,	
	2017	2016
Deferred tax assets:		
Net operating loss carryovers (1)	$ 0.2	$ 0.2
Accruals	1.4	1.6
Total deferred tax assets	1.6	1.8
Less: Deferred tax liabilities:		
Property, plant and equipment	58.0	50.5
Equity investment in partnerships	2.1	3.7
Total deferred tax liabilities	60.1	54.2
Total net deferred tax liabilities	$ 58.5	$ 52.4

(1) These losses expire in various years between 2018 and 2033 and are subject to limitations on their utilization.

Accounting guidance provides that a tax benefit from an uncertain tax position may be recognized when it is more likely than not that the position will be sustained upon examination, including resolutions of any related appeals or litigation processes, based on the technical merits. We did not rely on any uncertain tax positions in recording our income tax-related amounts during the years ended December 31, 2017, 2016 or 2015.

Note 17. 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 December 31, 2017 and 2016, our accruals for litigation contingencies were \$4.5 million and \$0.3 million, respectively, and were recorded in our Consolidated Balance Sheets as a component of "Other current liabilities." Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves uncertainties. In the event the assumptions we use to evaluate these matters change in future periods or new information becomes available, we may be required to record additional accruals. In an effort to mitigate expenses associated with litigation, we may settle legal proceedings out of court.

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

In September 2011, ETP filed suit against us and a third party in connection with the cancelled project alleging, among other things, that we and ETP had formed a "partnership." The case was tried in the District Court of Dallas County, Texas, 298th Judicial District. While we firmly believe, and argued during our defense, that no agreement was ever executed forming a legal joint venture or partnership between the parties, the jury found that the actions of the two companies, nevertheless, constituted a legal partnership. As a result, the jury found that ETP was wrongfully excluded from a subsequent pipeline project involving a third party, and awarded ETP \$319.4 million in actual damages on March 4, 2014. On July 29, 2014, the court entered judgment against us in an aggregate amount of \$535.8 million, which includes (i) \$319.4 million as the amount of actual damages awarded by the jury, (ii) an additional \$150.0 million in disgorgement for the alleged benefit we received due to a breach of fiduciary duties by us against ETP and (iii) prejudgment interest in the amount of \$66.4 million. The court also awarded post-judgment interest on such aggregate amount, to accrue at a rate of 5%, 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. As of December 31, 2017, we have not recorded a provision for this matter as management continues to believe that payment of damages by us in this case is not probable. We continue to monitor developments involving this matter.

PDH Litigation. In July 2013, we executed a contract with Foster Wheeler USA Corporation ("Foster Wheeler") pursuant to which Foster Wheeler was to serve as the general contractor responsible for the engineering, procurement, construction and installation of our 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.

Redelivery Commitments
We store natural gas, crude oil, NGLs and certain petrochemical products owned by third parties under various agreements. Under the terms of these agreements, we are generally required to redeliver volumes to the owner on demand. At December 31, 2017, we had approximately 9.0 trillion British thermal units ("TBtus") of natural gas, 15.8 MMBbls of crude oil, and 39.3 MMBbls of NGL and petrochemical products in our custody that were owned by third parties. We maintain insurance coverage related to such volumes that we believe is consistent with our exposure. See Note 18 for information regarding insurance matters.

Commitments Under Equity Compensation Plans of EPCO
In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us. See Notes 13 and 15 for additional information regarding our accounting for equity-based awards and related party information, respectively.

Contractual Obligations
The following table summarizes our various contractual obligations at December 31, 2017. A description of each type of contractual obligation follows:

	Payment or Settlement due by Period						
Contractual Obligations	**Total**	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**
Scheduled maturities of debt obligations	$ 24,780.1	$ 2,855.7	$ 1,500.0	$ 1,500.0	$ 575.0	$ 650.0	$ 17,699.4
Estimated cash interest payments	$ 23,942.0	$ 1,082.9	$ 1,022.1	$ 964.2	$ 912.1	$ 884.7	$ 19,076.0
Operating lease obligations	$ 413.3	$ 57.0	$ 52.8	$ 47.2	$ 40.0	$ 31.3	$ 185.0
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 1,911.5	$ 615.1	$ 528.6	$ 434.9	$ 332.9	$ --	$ --
NGLs	$ 99.0	$ 69.6	$ 29.4	$ --	$ --	$ --	$ --
Crude oil	$ 7,891.3	$ 1,352.3	$ 1,341.0	$ 945.8	$ 728.4	$ 728.4	$ 2,795.4
Petrochemicals & refined products	$ 632.1	$ 411.9	$ 214.1	$ 6.1	$ --	$ --	$ --
Other	$ 33.3	$ 9.3	$ 9.3	$ 7.6	$ 3.5	$ 1.4	$ 2.2
Underlying major volume commitments:							
Natural gas (in TBtus)	812	265	225	182	140	--	--
NGLs (in MMBbls)	7	5	2	--	--	--	--
Crude oil (in MMBbls)	471	38	55	51	47	47	233
Petrochemicals & refined products (in MMBbls)	11	7	4	--	--	--	--
Service payment commitments	$ 398.0	$ 98.3	$ 84.5	$ 60.0	$ 44.8	$ 43.1	$ 67.3
Capital expenditure commitments	$ 171.6	$ 171.6	$ --	$ --	$ --	$ --	$ --

Scheduled Maturities of Debt. We have long-term and short-term payment obligations under debt agreements. Amounts shown in the preceding table represent our scheduled future maturities of debt principal for the periods indicated. See Note 8 for additional information regarding our consolidated debt obligations.

Estimated Cash Interest Payments. Our estimated cash payments for interest are based on the principal amount of our consolidated debt obligations outstanding at December 31, 2017 and the contractually scheduled maturities of such balances. With respect to our variable-rate debt obligation, we applied the weighted-average interest rate paid during 2017 to determine the estimated cash payments. Our estimated cash payments for interest are significantly influenced by the long-term maturities of our $3.17 billion in junior subordinated notes. Our estimated cash payments for interest assume that these subordinated notes are not repaid prior to their respective maturity dates. We applied the current fixed interest rate through the respective maturity date for each junior subordinated note to determine the estimated cash payments for interest. See Note 8 for information regarding fixed and weighted-average variable interest rates charged in 2017.

Operating Lease Obligations. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year.

Our significant lease agreements consist of (i) land held pursuant to right-of-way agreements and property leases, (ii) the lease of underground storage caverns for natural gas and NGLs, (iii) the lease of transportation equipment used in our operations, and (iv) leased office space with affiliates of EPCO. Currently, our significant lease agreements have terms that range from 5 to 30 years. The agreements for leased office space with affiliates of EPCO and underground NGL storage caverns we lease from a third party include renewal options that could extend these contracts for up to an additional 20 years. The remainder of our significant lease agreements do not provide for additional renewal terms.

Lease expense is charged to operating costs and expenses on a straight-line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. We are generally required to perform routine maintenance on the underlying leased assets. In addition, certain leases give us the option to make leasehold improvements. Maintenance and repairs of leased assets resulting from our operations are charged to expense as incurred.

Consolidated costs and expenses include lease and rental expense amounts of $103.6 million, $110.1 million and $104.3 million during the years ended December 31, 2017, 2016 and 2015, respectively.

Purchase Obligations. We define purchase obligations as agreements with remaining terms in excess of one year to purchase goods or services that are enforceable and legally binding (i.e., unconditional) on us that specify all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We classify our unconditional purchase obligations into the following categories:

- We have long-term product purchase obligations for natural gas, NGLs, crude oil, petrochemicals and refined products with third party suppliers. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our volume commitments and estimated payment obligations under these contracts for the periods presented. Our estimated future payment obligations are based on the contractual price in each agreement at December 31, 2017 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.

- We have long-term commitments to pay service providers. Our contractual service payment commitments primarily represent our obligations under firm pipeline transportation contracts. Payment obligations vary by contract, but generally represent a price per unit of volume multiplied by a firm transportation volume commitment.

- We have short-term payment obligations relating to our capital spending program, including our share of the capital spending of our unconsolidated affiliates. These commitments represent unconditional payment obligations for services to be rendered or products to be delivered in connection with capital projects.

Other Commitments

In connection with the agreements to acquire EFS Midstream (see Note 12), we are obligated to spend up to an aggregate of $270 million on specified midstream gathering assets for PXD and Reliance, if requested by these producers, over a ten-year period. If constructed, these new assets would be owned by us and be a component of the EFS Midstream asset network. As of December 31, 2017, we have spent approximately $151 million of the $270 million commitment.

Other Long-Term Liabilities
The following table summarizes the components of "Other long-term liabilities" as presented on our Consolidated Balance Sheets at the dates indicated:

	December 31,	
	2017	2016
Noncurrent portion of AROs (see Note 5)	$ 81.1	$ 76.5
Deferred revenues – non-current portion (see Note 3)	135.5	137.0
Liquidity Option Agreement	333.9	269.6
Derivative liabilities	10.4	2.8
Centennial guarantees	4.5	5.3
Other	13.0	12.7
Total	$ 578.4	$ 503.9

Liquidity Option Agreement
We entered into a put option agreement (the "Liquidity Option Agreement" or "Liquidity Option") with OTA and Marquard & Bahls AG, a German corporation and the ultimate parent company of OTA ("M&B"), in connection with the Oiltanking acquisition (see Note 12). 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 then owned by OTA and assume all future income tax obligations of OTA associated with (i) owning common units encumbered by the entity-level taxes of a U.S. corporation and (ii) OTA's deferred tax liabilities. To the extent that the sum of OTA's deferred tax liabilities exceeds the then current book value of the Liquidity Option liability at the exercise date, we will recognize expense for the difference.

The aggregate consideration to be paid by us for OTA's capital stock would equal 100% of the then-current fair market value of the Enterprise common units owned by OTA at the exercise date. The consideration paid may be in the form of newly issued Enterprise common units, cash or any mix thereof, as determined solely by us. We have the ability to issue the requisite number of common units needed to satisfy any potential obligation under the Liquidity Option.

The Liquidity Option may be exercised prior to February 2020 if a Trigger Event (as defined in the underlying agreements) occurs. The exercise period for a Trigger Event is 135 days following the notice of such event. Trigger Events include, among other scenarios, any Enterprise Tax Event (as defined in the underlying agreements), which includes certain events in which OTA would recognize a taxable gain on the Enterprise common units that it owns.

The carrying value of the Liquidity Option Agreement, which is a component of "Other long-term liabilities" on our Consolidated Balance Sheet, was $333.9 million and $269.6 million at December 31, 2017 and 2016, respectively. The fair value of the Liquidity Option, at any measurement date, represents the present value of estimated federal and state income tax payments that we believe a market participant would incur on the future taxable income of OTA. We expect that OTA's taxable income would, in turn, be based on an allocation of our partnership's taxable income to the common units held by OTA and reflect certain tax planning strategies we believe could be employed.

Changes in the fair value of the Liquidity Option are recognized in earnings as a component of other income (expense) on our Statements of Consolidated Operations. Results for the years ended December 31, 2017, 2016 and 2015 include $64.3 million, $24.5 million and $25.4 million, respectively, of aggregate non-cash expense attributable to accretion and changes in management estimates regarding inputs to the valuation model.

The fair value of the Liquidity Option at December 31, 2017 reflects the estimated impact of the Tax Cuts and Jobs Act (the "TCJA") enacted by the U.S. Congress in late December 2017. The TCJA makes broad and complex changes to the U.S. tax code that will affect the carrying value of the Liquidity Option Agreement, including, but not limited to, (i) reducing the federal corporate tax rate payable by OTA from 35% to 21%, (ii) creating a new limitation on deductible interest expense, (iii) bonus depreciation that will allow for full expensing of qualified properties for certain tax years, and (iv) changing rules related to uses and limitations of OTA's net operating loss carryforwards created in tax years beginning after December 31, 2017. In connection with our initial analysis of the impact of the TCJA for the Liquidity Option, we have recorded an estimate resulting in the recognition of $21.2 million of non-cash expense, which is a component of the overall $64.3 million of non-cash expense we recognized for the Liquidity Option during the year ended December 31, 2017.

In addition to the effects of recently enacted tax reforms, our valuation estimate for the Liquidity Option at December 31, 2017 is based on several inputs that are not readily 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 will 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 December 31, 2017, 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 7.6% based on our weighted-average cost of capital at December 31, 2017.

Furthermore, our valuation estimate incorporates probability-weighted scenarios reflecting the likelihood that M&B may elect to divest a portion of the Enterprise common units held by OTA prior to exercise of the option. At December 31, 2017, based on these scenarios, we expect that OTA would own approximately 89% 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 at December 31, 2017 had assumed that OTA owned all of the Enterprise common units it received in Step 1 at the time of exercise (and all other inputs remained the same), the estimated fair value of the Liquidity Option liability would have increased by $40.2 million.

Centennial Guarantees
At December 31, 2017, Centennial's debt obligations consisted of $50.0 million borrowed under a master shelf loan agreement. Borrowings under the master shelf agreement mature in May 2024 and are collateralized by substantially all of Centennial's assets and severally guaranteed 50% by us and 50% by our joint venture partner in Centennial. If Centennial were to default on its debt obligations, we and our joint venture partner would each be required to make an approximate $25.0 million payment to Centennial's lenders in connection with the guarantee agreements (based on Centennial's debt principal outstanding at December 31, 2017). We recognized a liability of $3.7 million for our share of the Centennial debt guaranty at December 31, 2017.

In lieu of Centennial procuring insurance to satisfy third party claims arising from a catastrophic event, we and Centennial's other joint venture partner have entered a limited cash call agreement. We are obligated to contribute up to a maximum of $50.0 million in the event of a catastrophic event. At December 31, 2017, we have a recorded liability of $1.6 million representing the estimated fair value of our cash call guaranty. Our cash contributions to Centennial under the agreement may be covered by our other insurance policies depending on the nature of the catastrophic event.

Note 18. Significant Risks and Uncertainties

Nature of Operations
We operate predominantly 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.

The natural gas, NGLs and crude oil currently transported, gathered or processed at our facilities originate primarily from existing domestic resource basins, which naturally deplete over time. To offset this natural decline, our facilities need access to production from newly discovered properties. Many economic and business factors beyond our control can adversely affect the decision by producers to explore for and develop new reserves. These factors could include relatively low crude oil and natural gas prices, cost and availability of equipment and labor, regulatory changes, capital budget limitations, the lack of available capital or the probability of success in finding hydrocarbons. A decrease in exploration and development activities in the regions where our facilities and other energy logistics assets are located could result in a decrease in volumes handled by our assets, which could have a material adverse effect on our financial position, results of operations and cash flows.

Even if crude oil and natural gas reserves exist in the areas served by our assets, we may not be chosen by producers in these areas to gather, transport, process, fractionate, store or otherwise handle the hydrocarbons extracted. We compete with other companies, including producers of crude oil and natural gas, for any such production on the basis of many factors, including but not limited to geographic proximity to the production, costs of connection, available capacity, rates and access to markets.

Credit Risk

We may incur credit risk to the extent counterparties do not fulfill their obligations to us in connection with our marketing of natural gas, NGLs, petrochemicals, refined products and crude oil and long-term contracts with minimum volume commitments or fixed demand charges. Risks of nonpayment and nonperformance by customers are a major consideration in our businesses, and our credit procedures and policies may not be adequate to sufficiently eliminate customer credit risk. Further, adverse economic conditions in our industry, such as those experienced in 2015 and 2016, increase the risk of nonpayment and nonperformance by customers, particularly customers that have sub-investment grade credit ratings or small-scale companies. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments, net out agreements and guarantees. However, these procedures and policies do not fully eliminate customer credit risk.

Our primary markets are located in the Gulf Coast, Southwest, Rocky Mountain, Northeast and Midwest regions of the U.S. We have a concentration of trade receivable balances due from independent and major integrated oil and gas companies and other pipelines and wholesalers. These concentrations of market areas may affect our overall credit risk in that these energy industry customers may be similarly affected by changes in economic, regulatory or other factors.

In those situations where we are exposed to credit risk in our derivative instrument transactions, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis. Generally, we do not require collateral for such transactions nor do we currently anticipate nonperformance by our material counterparties.

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance may not fully cover every type of damage, interruption or other loss that might occur. If we were to incur a significant loss for which we were not fully insured, it could have a material impact on our financial position, results of operations and cash flows.

In addition, there may be timing differences between amounts we accrue related to property damage expense, amounts we are required to pay in connection with a loss, and amounts we subsequently receive from insurance carriers as reimbursements. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material expenditures not reimbursed by insurance, could reduce our ability to pay distributions to our unitholders and, accordingly, adversely affect the market price of our common units.

Involuntary conversions result from the loss of an asset due to some unforeseen event (e.g., destruction due to a fire). Some of these events are covered by insurance, thus resulting in a property damage insurance recovery. Amounts we receive from insurance carriers are net of any deductibles related to the covered event. We record a receivable from insurance to the extent we recognize a loss from an involuntary conversion event and the likelihood of our recovering such loss is deemed probable. To the extent that any of our insurance claim receivables are later judged not probable of recovery (e.g., due to new information), such amounts are expensed. We recognize gains on involuntary conversions when the amount received from insurance exceeds the net book value of the retired assets.

In addition, we do not recognize gains related to insurance recoveries until all contingencies related to such proceeds have been resolved, that is, a non-refundable cash payment is received from the insurance carrier or we have a binding settlement agreement with the carrier that clearly states that a non-refundable payment will be made. To the extent that an asset is rebuilt, the associated expenditures are capitalized, as appropriate, on our Consolidated Balance Sheets and presented as "Capital expenditures" on our Statements of Consolidated Cash Flows.

Under our current insurance program, the standalone deductible for property damage claims is $30 million. We also have business interruption protection; however, such claims must involve physical damage and have a combined loss value in excess of $30 million and the period of interruption must exceed 60 days. With respect to named windstorm claims, the maximum amount of insurance coverage available to us for any single event is $200 million, after applying the appropriate deductibles. A named windstorm is a hurricane, typhoon, tropical storm or cyclone as declared by the U.S. National Weather Service.

Note 19. Supplemental Cash Flow Information

The following table provides information regarding the net effect of changes in our operating accounts and cash payments for interest and income taxes for the periods indicated:

	For the Year Ended December 31,		
	2017	2016	2015
Decrease (increase) in:			
Accounts receivable – trade	$ (1,076.2)	$ (679.0)	$ 1,279.3
Accounts receivable – related parties	(0.7)	0.4	1.3
Inventories	194.6	(871.8)	(72.7)
Prepaid and other current assets	226.0	(49.3)	(59.1)
Other assets	(111.0)	(2.0)	(5.8)
Increase (decrease) in:			
Accounts payable – trade	66.6	(21.5)	(52.9)
Accounts payable – related parties	56.0	21.0	(34.8)
Accrued product payables	952.3	1,193.3	(1,342.4)
Accrued interest	17.3	(11.4)	16.5
Other current liabilities	(291.4)	189.9	(67.1)
Other liabilities	(1.3)	49.5	14.4
Net effect of changes in operating accounts	$ 32.2	$ (180.9)	$ (323.3)
Cash payments for interest, net of $192.1, $168.2 and $149.1 capitalized in 2017, 2016 and 2015, respectively	$ 912.1	$ 947.9	$ 911.6
Cash payments for federal and state income taxes	$ 20.9	$ 18.7	$ 17.5

We incurred liabilities for construction in progress that had not been paid at December 31, 2017, 2016 and 2015 of $373.0 million, $124.3 million and $472.8 million, respectively. Such amounts are not included under the caption "Capital expenditures" on our Statements of Consolidated Cash Flows.

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

	For the Year Ended December 31,		
	2017	2016	2015
Sale of Offshore Business (see Note 10)	$ --	$ --	$ 1,527.7
Cash proceeds from other asset sales	40.1	46.5	80.9
Total	$ 40.1	$ 46.5	$ 1,608.6

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

	For the Year Ended December 31,		
	2017	2016	2015
Sale of Offshore Business (see Note 10)	$ --	$ --	$ (12.3)
Net gains (losses) attributable to other asset sales	10.7	2.5	(3.3)
Total	$ 10.7	$ 2.5	$ (15.6)

In July 2015, we purchased EFS Midstream for approximately $2.1 billion in cash, which was payable in two installments. The initial payment of $1.1 billion was paid in July 2015, with the second and final installment of $1.0 billion paid in July 2016. See Note 12 for information regarding this business combination.

See Note 12 for information regarding non-cash consideration we issued in connection with Step 2 of the Oiltanking acquisition.

See Note 14 for information regarding asset impairment and related charges as presented on our Statements of Consolidated Cash Flows.

Note 20. Quarterly Financial Information (Unaudited)

The following table presents selected quarterly financial data for the periods indicated:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2017:				
Revenues	$ 7,320.4	$ 6,607.6	$ 6,886.9	$ 8,426.6
Operating income	1,031.6	938.7	879.2	1,079.4
Net income	771.0	666.0	621.3	797.3
Net income attributable to limited partners	760.7	653.7	610.9	774.0
Earnings per unit:				
Basic	$ 0.36	$ 0.30	$ 0.28	$ 0.36
Diluted	$ 0.36	$ 0.30	$ 0.28	$ 0.36
For the Year Ended December 31, 2016:				
Revenues	$ 5,005.3	$ 5,617.8	$ 5,920.4	$ 6,478.8
Operating income	915.6	836.9	905.0	923.2
Net income	670.2	570.0	643.1	669.7
Net income attributable to limited partners	661.2	558.5	634.6	658.8
Earnings per unit:				
Basic	$ 0.32	$ 0.27	$ 0.30	$ 0.31
Diluted	$ 0.32	$ 0.27	$ 0.30	$ 0.31

The sum of our quarterly earnings per unit amounts may not equal our full year amounts due to slight rounding differences.

Note 21. 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 8 for additional information regarding our consolidated debt obligations.

There are no significant restrictions on the ability of EPO to receive funds from Enterprise Products Partners L.P.

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

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

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Operations
For the Year Ended 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
Revenues	$ 40,696.8	$ 18,451.2	$ (29,906.5)	$ 29,241.5	$ --	$ --	$ 29,241.5
Costs and expenses:							
Operating costs and expenses	39,809.6	15,654.9	(29,907.0)	25,557.5	--	--	25,557.5
General and administrative costs	31.4	148.0	(0.1)	179.3	1.8	--	181.1
Total costs and expenses	39,841.0	15,802.9	(29,907.1)	25,736.8	1.8	--	25,738.6
Equity in income of unconsolidated affiliates	2,990.1	566.8	(3,130.9)	426.0	2,865.4	(2,865.4)	426.0
Operating income	3,845.9	3,215.1	(3,130.3)	3,930.7	2,863.6	(2,865.4)	3,928.9
Other income (expense):							
Interest expense	(982.5)	(11.8)	9.7	(984.6)	--	--	(984.6)
Other, net	9.2	1.8	(9.7)	1.3	(64.3)	--	(63.0)
Total other expense, net	(973.3)	(10.0)	--	(983.3)	(64.3)	--	(1,047.6)
Income before income taxes	2,872.6	3,205.1	(3,130.3)	2,947.4	2,799.3	(2,865.4)	2,881.3
Provision for income taxes	(12.0)	(13.7)	--	(25.7)	--	--	(25.7)
Net income	2,860.6	3,191.4	(3,130.3)	2,921.7	2,799.3	(2,865.4)	2,855.6
Net loss (income) attributable to noncontrolling interests	--	(6.5)	(55.1)	(61.6)	--	5.3	(56.3)
Net income attributable to entity	$ 2,860.6	$ 3,184.9	$ (3,185.4)	$ 2,860.1	$ 2,799.3	$ (2,860.1)	$ 2,799.3

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2016

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 28,958.7	$ 15,296.8	$ (21,233.2)	$ 23,022.3	$ --	$ --	$ 23,022.3
Costs and expenses:							
Operating costs and expenses	28,108.2	12,768.9	(21,233.6)	19,643.5	--	--	19,643.5
General and administrative costs	22.5	135.3	--	157.8	2.3	--	160.1
Total costs and expenses	28,130.7	12,904.2	(21,233.6)	19,801.3	2.3	--	19,803.6
Equity in income of unconsolidated affiliates	2,686.1	521.7	(2,845.8)	362.0	2,539.9	(2,539.9)	362.0
Operating income	3,514.1	2,914.3	(2,845.4)	3,583.0	2,537.6	(2,539.9)	3,580.7
Other income (expense):							
Interest expense	(973.1)	(17.3)	7.8	(982.6)	--	--	(982.6)
Other, net	8.3	2.3	(7.8)	2.8	(24.5)	--	(21.7)
Total other expense, net	(964.8)	(15.0)	--	(979.8)	(24.5)	--	(1,004.3)
Income before income taxes	2,549.3	2,899.3	(2,845.4)	2,603.2	2,513.1	(2,539.9)	2,576.4
Provision for income taxes	(13.1)	(8.2)	--	(21.3)	--	(2.1)	(23.4)
Net income	2,536.2	2,891.1	(2,845.4)	2,581.9	2,513.1	(2,542.0)	2,553.0
Net loss (income) attributable to noncontrolling interests	--	(7.4)	(37.8)	(45.2)	--	5.3	(39.9)
Net income attributable to entity	$ 2,536.2	$ 2,883.7	$ (2,883.2)	$ 2,536.7	$ 2,513.1	$ (2,536.7)	$ 2,513.1

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2015

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 20,104.8	$ 19,087.0	$ (12,163.9)	$ 27,027.9	$ --	$ --	$ 27,027.9
Costs and expenses:							
Operating costs and expenses	19,283.7	16,549.3	(12,164.3)	23,668.7	--	--	23,668.7
General and administrative costs	38.2	152.3	--	190.5	2.1	--	192.6
Total costs and expenses	19,321.9	16,701.6	(12,164.3)	23,859.2	2.1	--	23,861.3
Equity in income of unconsolidated affiliates	2,718.4	417.5	(2,762.3)	373.6	2,548.7	(2,548.7)	373.6
Operating income	3,501.3	2,802.9	(2,761.9)	3,542.3	2,546.6	(2,548.7)	3,540.2
Other income (expense):							
Interest expense	(952.9)	(12.0)	3.1	(961.8)	--	--	(961.8)
Other, net	5.2	0.8	(3.1)	2.9	(25.4)	--	(22.5)
Total other expense, net	(947.7)	(11.2)	--	(958.9)	(25.4)	--	(984.3)
Income before income taxes	2,553.6	2,791.7	(2,761.9)	2,583.4	2,521.2	(2,548.7)	2,555.9
Provision for income taxes	(8.7)	12.7	--	4.0	--	(1.5)	2.5
Net income	2,544.9	2,804.4	(2,761.9)	2,587.4	2,521.2	(2,550.2)	2,558.4
Net loss (income) attributable to noncontrolling interests	--	0.9	(42.9)	(42.0)	--	4.8	(37.2)
Net income attributable to entity	$ 2,544.9	$ 2,805.3	$ (2,804.8)	$ 2,545.4	$ 2,521.2	$ (2,545.4)	$ 2,521.2

**Enterprise Products Partners L.P.
Condensed Consolidating Statement of Comprehensive Income
For the Year Ended 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
Comprehensive income	$ 2,951.7	$ 3,208.6	$ (3,130.2)	$ 3,030.1	$ 2,907.6	$ (2,973.8)	$ 2,963.9
Comprehensive loss (income) attributable to noncontrolling interests	--	(6.5)	(55.1)	(61.6)	--	5.3	(56.3)
Comprehensive income attributable to entity	$ 2,951.7	$ 3,202.1	$ (3,185.3)	$ 2,968.5	$ 2,907.6	$ (2,968.5)	$ 2,907.6

**Enterprise Products Partners L.P.
Condensed Consolidating Statement of Comprehensive Income
For the Year Ended December 31, 2016**

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 2,544.3	$ 2,822.1	$ (2,845.3)	$ 2,521.1	$ 2,452.2	$ (2,481.1)	$ 2,492.2
Comprehensive loss (income) attributable to noncontrolling interests	--	(7.4)	(37.8)	(45.2)	--	5.3	(39.9)
Comprehensive income attributable to entity	$ 2,544.3	$ 2,814.7	$ (2,883.1)	$ 2,475.9	$ 2,452.2	$ (2,475.8)	$ 2,452.3

**Enterprise Products Partners L.P.
Condensed Consolidating Statement of Comprehensive Income
For the Year Ended December 31, 2015**

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 2,578.6	$ 2,793.1	$ (2,761.9)	$ 2,609.8	$ 2,543.6	$ (2,572.6)	$ 2,580.8
Comprehensive loss (income) attributable to noncontrolling interests	--	0.9	(42.9)	(42.0)	--	4.8	(37.2)
Comprehensive income attributable to entity	$ 2,578.6	$ 2,794.0	$ (2,804.8)	$ 2,567.8	$ 2,543.6	$ (2,567.8)	$ 2,543.6

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Cash Flows
For the Year Ended 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
Operating activities:							
Net income	$ 2,860.6	$ 3,191.4	$ (3,130.3)	$ 2,921.7	$ 2,799.3	$ (2,865.4)	$ 2,855.6
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	216.6	1,427.8	(0.4)	1,644.0	--	--	1,644.0
Equity in income of unconsolidated affiliates	(2,990.1)	(566.8)	3,130.9	(426.0)	(2,865.4)	2,865.4	(426.0)
Distributions received on earnings from unconsolidated affiliates	1,162.8	272.7	(1,001.8)	433.7	3,574.6	(3,574.6)	433.7
Net effect of changes in operating accounts and other operating activities	2,812.2	(2,726.3)	(19.1)	66.8	93.2	(1.0)	159.0
Net cash flows provided by operating activities	4,062.1	1,598.8	(1,020.7)	4,640.2	3,601.7	(3,575.6)	4,666.3
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(846.8)	(2,255.0)	--	(3,101.8)	--	--	(3,101.8)
Cash used for business combinations, net of cash received	(7.3)	(191.4)	--	(198.7)	--	--	(198.7)
Proceeds from asset sales	17.0	23.1	--	40.1	--	--	40.1
Other investing activities	(1,908.5)	(28.0)	1,910.8	(25.7)	(1,060.5)	1,060.5	(25.7)
Cash used in investing activities	(2,745.6)	(2,451.3)	1,910.8	(3,286.1)	(1,060.5)	1,060.5	(3,286.1)
Financing activities:							
Borrowings under debt agreements	69,349.3	--	(34.0)	69,315.3	--	--	69,315.3
Repayments of debt	(68,459.5)	(0.1)	--	(68,459.6)	--	--	(68,459.6)
Cash distributions paid to partners	(3,574.6)	(1,065.3)	1,065.3	(3,574.6)	(3,569.9)	3,574.6	(3,569.9)
Cash payments made in connection with DERs	--	--	--	--	(15.1)	--	(15.1)
Cash distributions paid to noncontrolling interests	--	(9.6)	(40.6)	(50.2)	--	1.0	(49.2)
Cash contributions from noncontrolling interests	--	0.1	0.3	0.4	--	--	0.4
Net cash proceeds from issuance of common units	--	--	--	--	1,073.4	--	1,073.4
Cash contributions from owners	1,060.5	1,900.0	(1,900.0)	1,060.5	--	(1,060.5)	--
Other financing activities	6.8	--	--	6.8	(29.6)	--	(22.8)
Cash provided by (used in) financing activities	(1,617.5)	825.1	(909.0)	(1,701.4)	(2,541.2)	2,515.1	(1,727.5)
Net change in cash, cash equivalents and restricted cash	(301.0)	(27.4)	(18.9)	(347.3)	--	--	(347.3)
Cash, cash equivalents and restricted cash, January 1	366.2	58.9	(7.5)	417.6	--	--	417.6
Cash, cash equivalents and restricted cash, December 31	$ 65.2	$ 31.5	$ (26.4)	$ 70.3	$ --	$ --	$ 70.3

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2016

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 2,536.2	$ 2,891.1	$ (2,845.4)	$ 2,581.9	$ 2,513.1	$ (2,542.0)	$ 2,553.0
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	185.4	1,367.0	(0.4)	1,552.0	--	--	1,552.0
Equity in income of unconsolidated affiliates	(2,686.1)	(521.7)	2,845.8	(362.0)	(2,539.9)	2,539.9	(362.0)
Distributions received on earnings from unconsolidated affiliates	1,127.3	265.9	(1,012.7)	380.5	3,331.2	(3,331.2)	380.5
Net effect of changes in operating accounts and other operating activities	2,448.6	(2,568.5)	43.1	(76.8)	18.9	1.2	(56.7)
Net cash flows provided by operating activities	3,611.4	1,433.8	(969.6)	4,075.6	3,323.3	(3,332.1)	4,066.8
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(1,327.4)	(1,656.7)	--	(2,984.1)	--	--	(2,984.1)
Cash used for business combinations, net of cash received	--	(1,000.0)	--	(1,000.0)	--	--	(1,000.0)
Proceeds from asset sales	28.8	17.7	--	46.5	--	--	46.5
Other investing activities	(2,301.9)	(63.2)	2,296.9	(68.2)	(2,530.9)	2,530.9	(68.2)
Cash used in investing activities	(3,600.5)	(2,702.2)	2,296.9	(4,005.8)	(2,530.9)	2,530.9	(4,005.8)
Financing activities:							
Borrowings under debt agreements	62,813.9	41.8	(41.8)	62,813.9	--	--	62,813.9
Repayments of debt	(61,672.5)	(0.1)	--	(61,672.6)	--	--	(61,672.6)
Cash distributions paid to partners	(3,331.2)	(1,089.6)	1,089.6	(3,331.2)	(3,300.5)	3,331.2	(3,300.5)
Cash payments made in connection with DERs	--	--	--	--	(11.7)	--	(11.7)
Cash distributions paid to noncontrolling interests	--	(8.5)	(39.8)	(48.3)	--	0.9	(47.4)
Cash contributions from noncontrolling interests	--	20.4	--	20.4	--	--	20.4
Net cash proceeds from issuance of common units	--	--	--	--	2,542.8	--	2,542.8
Cash contributions from owners	2,530.9	2,292.2	(2,292.2)	2,530.9	--	(2,530.9)	--
Other financing activities	(0.2)	--	--	(0.2)	(23.0)	--	(23.2)
Cash provided by (used in) financing activities	340.9	1,256.2	(1,284.2)	312.9	(792.4)	801.2	321.7
Net change in cash, cash equivalents and restricted cash	351.8	(12.2)	43.1	382.7	--	--	382.7
Cash, cash equivalents and restricted cash, January 1	14.4	71.1	(50.6)	34.9	--	--	34.9
Cash, cash equivalents and restricted cash, December 31	$ 366.2	$ 58.9	$ (7.5)	$ 417.6	$ --	$ --	$ 417.6

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2015

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 2,544.9	$ 2,804.4	$ (2,761.9)	$ 2,587.4	$ 2,521.2	$ (2,550.2)	$ 2,558.4
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	144.9	1,371.5	(0.4)	1,516.0	--	--	1,516.0
Equity in income of unconsolidated affiliates	(2,718.4)	(417.5)	2,762.3	(373.6)	(2,548.7)	2,548.7	(373.6)
Distributions received on earnings from unconsolidated affiliates	1,989.6	307.7	(1,835.2)	462.1	3,000.2	(3,000.2)	462.1
Net effect of changes in operating accounts and other operating activities	882.8	(1,031.0)	(35.9)	(184.1)	22.1	1.5	(160.5)
Net cash flows provided by operating activities	2,843.8	3,035.1	(1,871.1)	4,007.8	2,994.8	(3,000.2)	4,002.4
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(1,180.0)	(2,631.6)	--	(3,811.6)	--	--	(3,811.6)
Cash used for business combinations, net of cash received	(1,069.9)	13.4	--	(1,056.5)	--	--	(1,056.5)
Proceeds from asset sales	1,531.3	77.3	--	1,608.6	--	--	1,608.6
Other investing activities	(1,499.0)	(1,246.7)	2,579.3	(166.4)	(1,179.8)	1,179.8	(166.4)
Cash used in investing activities	(2,217.6)	(3,787.6)	2,579.3	(3,425.9)	(1,179.8)	1,179.8	(3,425.9)
Financing activities:							
Borrowings under debt agreements	21,081.1	133.9	(133.9)	21,081.1	--	--	21,081.1
Repayments of debt	(19,867.2)	--	--	(19,867.2)	--	--	(19,867.2)
Cash distributions paid to partners	(3,000.2)	(1,882.4)	1,882.4	(3,000.2)	(2,943.7)	3,000.2	(2,943.7)
Cash payments made in connection with DERs	--	--	--	--	(7.7)	--	(7.7)
Cash distributions paid to noncontrolling interests	--	(0.8)	(47.2)	(48.0)	--	--	(48.0)
Cash contributions from noncontrolling interests	--	54.4	(0.4)	54.0	--	--	54.0
Net cash proceeds from issuance of common units	--	--	--	--	1,188.6	--	1,188.6
Cash contributions from owners	1,179.8	2,445.0	(2,445.0)	1,179.8	--	(1,179.8)	--
Other financing activities	(24.0)	3.1	--	(20.9)	(52.2)	--	(73.1)
Cash provided by (used in) financing activities	(630.5)	753.2	(744.1)	(621.4)	(1,815.0)	1,820.4	(616.0)
Net change in cash, cash equivalents and restricted cash	(4.3)	0.7	(35.9)	(39.5)	--	--	(39.5)
Cash, cash equivalents and restricted cash, January 1	18.7	70.4	(14.7)	74.4	--	--	74.4
Cash, cash equivalents and restricted cash, December 31	$ 14.4	$ 71.1	$ (50.6)	$ 34.9	$ --	$ --	$ 34.9

Note 22. Subsequent Events

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"). We issued these notes using our 2016 Shelf (see Note 9).

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 expected redemption of all $682.7 million outstanding aggregate principal amount of its 7.034% Junior Subordinated Notes B (the "7.034% Notes").

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.

The redemption of the 7.034% Notes and the issuance of the 5.375% Junior Subordinated Notes F will result in annual interest savings to EPO of approximately $11.3 million. On February 1, 2018, EPO notified its trustee and paying agent to redeem all of the $682.7 million outstanding aggregate principal amount of its 7.034% Notes. EPO anticipates that the 7.034% Notes will be redeemed on or about March 5, 2018, in accordance with the terms of the 7.034% Notes, 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.