ENTERPRISE PRODUCTS PARTNERS L P
Form 10-K
March 01, 2019

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, 2018

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

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.
(Exact name of Registrant as Specified in Its Charter)

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

1100 LOUISIANA STREET, 10th FLOOR, HOUSTON, TEXAS 77002
(Address of Principal Executive Offices) (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 þ 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 29, 2018 (the last business day of the registrant's most recently completed second fiscal quarter) was $41.02 billion based on a closing price on that date of $27.67 per common unit on the New York Stock Exchange Composite ticker tape. There were 2,184,873,868 common units outstanding at January 31, 2019.

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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, who is also an advisory director of Enterprise GP. 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 the President and Chief Financial Officer 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 Financial Officer of EPCO. EPCO, together with its privately held affiliates, owned approximately 31.9% of our limited partner interests at December 31, 2018.

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, 2018 (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,” “ “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.

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PART I

ITEMS 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 49,200 miles of pipelines; 260 MMBbls of storage capacity for NGLs, crude oil, petrochemicals and refined products; and 14 Bcf of natural gas storage capacity.

The safe operation of our assets is a top priority. 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. For additional information, see "Environmental, Safety and Conservation" within the Regulatory Matters section of this Part I, Items 1 and 2 discussion.

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, 2019, 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 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

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§ share capital costs and risks through business 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 2019

For information regarding our commercial and liquidity outlook for the year ending December 31, 2019, see "General Outlook for 2019" 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 the years ended December 31, 2018, 2017 and 2016 was Vitol Holding B.V. and its affiliates (collectively, "Vitol"), which accounted for 7.8%, 11.2% and 9.9%, respectively, of our consolidated revenues. Vitol is a global energy and commodity trading company.

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, Items 1 and 2 discussion.

For management's discussion and analysis of our results of operations, liquidity and capital resources and capital investment 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.

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NGL Pipelines & Services Segment

Our NGL Pipelines & Services business segment currently includes 26 natural gas processing plants and related NGL marketing activities; approximately 19,200 miles of NGL pipelines; NGL and related product storage facilities; and 16 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 26 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 other impurities. Once the natural gas is processed and NGLs and impurities are removed, the residue natural gas meets pipeline and commercial quality specifications. Natural gas that has a high NGL content is referred to as “rich” or “wet” natural gas, whereas natural gas from the wellhead that is relatively free of NGLs and impurities is referred to as “lean” or “dry” natural gas. Dry natural gas can be shipped on pipelines and used as fuel with little to no processing.

In general, on an energy-equivalent basis, most NGLs have greater economic value as feedstock for petrochemical and motor gasoline production than as components of a natural gas stream. Once the mixed NGLs are extracted at a natural gas processing plant, they are transported to a centralized fractionation facility for separation into purity NGL products (ethane, propane, normal butane, isobutane and natural gasoline). Typical uses of purity NGL products include the following:

§ 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. 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. 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 terms of our natural gas processing agreements typically range from month-to-month to life of the associated production lease, with intermediate terms of one to ten years being common.

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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, 2018, we estimate that approximately 47% of our current portfolio of natural gas processing contracts (based on natural gas inlet volumes) were entirely fee-based, with an additional 25% of this portfolio reflecting a combination of fee-based and commodity-based terms. The terms of the remaining 28% of our portfolio of natural gas processing contracts were entirely commodity-based.

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 spot and term sales of NGLs that 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 800 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 150 tractor-trailer tank trucks that are used to transport LPG for us and on behalf of third parties. We lease and operate the majority of these trucks and trailers.

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The following table presents selected information regarding our natural gas processing facilities at February 1, 2019:

Plant Name	Location(s)	Production Region Served	Ownership Interest		Net Gas Processing Capacity (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
North Terrebonne	Louisiana	Gulf of Mexico	83.0%	(2)	789	950
Chaco	New Mexico	San Juan	100.0%		600	600
Orla	Texas	Delaware	100.0%		600	600
Neptune	Louisiana	Gulf of Mexico	66.0%	(2)	430	650
Sea Robin	Louisiana	Gulf of Mexico	54.1%	(2)	352	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
San Martin	Texas	Eagle Ford	100.0%		200	200
South Eddy	New Mexico	Delaware	100.0%		200	200
Waha (3)	Texas	Delaware	100.0%		150	150
Delmita	Texas	Frio-Vicksburg	100.0%		145	145
Carlsbad	New Mexico	Delaware	100.0%		130	130
Panola	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%	(4)	98	750
Indian Springs	Texas	Wilcox-Woodbine	75.0%	(2)	90	120
Chaparral	New Mexico	Delaware	100.0%		45	45
Fairway	Texas	Cotton Valley	100.0%		5	5
Total					10,549	11,910

(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) Prior to March 2018, our ownership in the Waha plant was held through our 50% equity investment in Delaware Basin Gas Processing LLC ("Delaware Processing"). We acquired the remaining 50% equity interest in Delaware Processing in March 2018 for $150.6 million in cash. For information regarding this transaction, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.
(4) Our ownership in the Venice plant is held indirectly through our equity method investment in Venice Energy Services Company, L.L.C.

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 52.7%, 51.8% and 50.8% for the years ended

December 31, 2018, 2017 and 2016, respectively.

Orla natural gas processing facility. 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. 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 own and operate the Orla facility.

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The Orla facility will be completed in three stages. The first processing train ("Orla I"), which commenced operations in May 2018, has a natural gas processing capacity of 300 MMcf/d and the capability to extract more than 40 MBPD of mixed NGLs. In conjunction with the start-up of Orla I, we placed into service approximately 70 miles of residue natural gas pipelines that connect Orla to our Texas Intrastate System. We also placed into service a 30-mile extension of our NGL system that provides customers at Orla with NGL takeaway capacity and direct access to our integrated network of downstream NGL assets. A second processing train ("Orla II"), which commenced operations in October 2018, added 300 MMcf/d of incremental processing capacity to the Orla facility and increased the overall extraction rate for mixed NGLs up to 80 MBPD. A third processing train (Orla III) is scheduled to be completed in the second quarter of 2019. 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.

Mentone natural gas processing facility. In October 2018, we announced that construction of our Mentone cryogenic natural gas processing plant had commenced. The Mentone plant, which is located in Loving County, Texas, is expected to have the capacity to process 300 MMcf/d of natural gas and extract more than 40 MBPD of NGLs. The project is scheduled to be completed in the first quarter of 2020 and is supported by a long-term acreage dedication agreement.

The Mentone plant further extends our presence in the growing Delaware Basin and provides access to our fully integrated midstream asset network. To support the development of Mentone, we are constructing approximately 70 miles of gathering and residue pipelines and expanding compression capabilities. These projects will allow the Mentone plant to link to our NGL system, including the Shin Oak NGL Pipeline which entered limited commercial service in February 2019, as well as our Texas Intrastate System. We will own and operate the Mentone facility and related infrastructure.

When the Mentone plant is completed and placed into service, we expect to have an aggregate 1.6 Bcf/d of natural gas processing capacity and 250 MBPD of NGL production from our processing plants in the Delaware Basin.

NGL pipelines

Our NGL pipelines transport mixed NGLs from natural gas processing plants, refineries and marine terminals to downstream fractionation plants and storage facilities; gather and distribute purity NGL products to and from fractionation plants, storage and terminal facilities, petrochemical plants, refineries and export facilities; and deliver propane and ethane to destinations along our 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, Items 1 and 2 for additional information regarding governmental oversight of our liquids pipelines.

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

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The following table presents selected information regarding our NGL pipelines at February 1, 2019:

Description of Asset	Location(s)	Ownership Interest	Pipeline Length (Miles)
Mid-America Pipeline System (1)	Midwest and Western U.S.	100.0%	8,035
South Texas NGL Pipeline System	Texas	100.0%	1,917
Dixie Pipeline (1)	South and Southeastern U.S.	100.0%	1,307
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
Seminole NGL Pipeline (1,2)	Texas	100.0%	869
Texas Express Pipeline (1)	Texas	35.0%	594
Skelly-Belvieu Pipeline (1)	Texas, Oklahoma	50.0%	572
Front Range Pipeline (1)	Colorado, Oklahoma, Texas	33.3%	447
Aegis Ethane Pipeline (1)	Texas, Louisiana	100.0%	299
Houston Ship Channel Pipeline System	Texas	100.0%	275
Rio Grande Pipeline (1)	Texas	70.0%	249
Panola Pipeline (1)	Texas	55.0%	249
Lou-Tex NGL Pipeline (1)	Texas, Louisiana	100.0%	206
Promix NGL Gathering System	Louisiana	50.0%	201
Texas Express Gathering System	Texas	45.0%	170
Tri-States NGL Pipeline (1)	Alabama, Mississippi, Louisiana	83.3%	168
Others (seven systems) (3)	Various	Various (4)	454
Total			19,239

(1) Interstate transportation services provided by these liquids pipelines, in whole or part, are regulated by federal governmental agencies.
(2) Pipeline mileage shown for the Seminole NGL Pipeline excludes 379 miles converted to crude oil service in February 2019 and used by our Midland-to-ECHO 2 Pipeline System.
(3) Includes our Belle Rose and Wilprise pipelines located in the coastal regions of Louisiana; two pipelines located near Port Arthur 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.
(4) 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 operating rates achieved at a given point in time between various segments of each system (e.g., demand levels at each injection and 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. In the aggregate, net throughput volumes for these pipelines were 3,461 MBPD, 3,168 MBPD and 2,965 MBPD during the years ended December 31, 2018, 2017 and 2016, respectively.

The following information describes 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 3,119-mile Rocky Mountain pipeline, the 2,138-mile Conway North pipeline, the 632-mile Ethane-Propane ("EP") Mix pipeline, and the 2,146-mile Conway South 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. Volumes transported on the Mid-America Pipeline System primarily originate from natural gas processing plants located in the Rocky Mountains and Mid-Continent regions, as well as NGL fractionation and storage facilities in Kansas and Texas.

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The Rocky Mountain pipeline transports mixed NGLs from production fields located in 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 Mont Belvieu, Hobbs and Conway, provide buyers and sellers with a centralized location for the storage and pricing of products, while also providing connections to intrastate and/or interstate pipelines. The EP Mix segment transports EP mix from the Conway hub to petrochemical plants in Iowa and Illinois. 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 NGL 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.

§ The South Texas NGL Pipeline System is a network of NGL gathering and transportation pipelines located in South Texas that gather and transport mixed NGLs from natural gas processing plants (owned by either us or third parties) located in South Texas to our NGL fractionators in South Texas and NGL fractionation and storage complex located in and near Mont Belvieu, Texas. The Mont Belvieu area in Chambers County, Texas, with its significant energy-related infrastructure, is a key hub of the global NGL industry (the “Mont Belvieu hub”). 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 other NGL pipelines and to our Mont Belvieu storage complex. The South Texas NGL Pipeline System is a component of our ethane header system, extending it from the Mont Belvieu hub to Corpus Christi, Texas.

§ The Dixie Pipeline transports propane and other NGLs and extends from southeast Texas to markets in the southeastern U.S. Propane supplies transported on this system primarily originate from southeast Texas, south Louisiana and Mississippi. The Dixie Pipeline 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 ATEX, or Appalachia-to-Texas Express, pipeline transports ethane in southbound service from 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 located in West Texas and New Mexico to Mont Belvieu. 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.

§ The Seminole NGL Pipeline transports NGLs from the Hobbs hub and the Permian Basin to markets in southeast Texas, including our NGL fractionation complex located in and near Mont Belvieu. NGLs originating on the Mid-America Pipeline System are a significant source of throughput for the Seminole NGL Pipeline.

Historically, the Seminole NGL Pipeline system was comprised of two parallel pipelines extending to Mont Belvieu. In January 2019, we completed the conversion of a portion of one of these pipelines from NGL service to crude oil service. The conversion does not reduce our NGL transportation capacity since displaced NGLs are transported using our other NGL pipelines, including our Shin Oak NGL Pipeline. Furthermore, we have the ability to convert this pipeline back to NGL service should market and physical takeaway conditions warrant. See "Crude Oil Pipelines & Services Segment – Crude Oil Pipelines" within this Items 1 and 2 section for additional information regarding the Midland-to-ECHO 2 Pipeline System.

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- The Texas Express Pipeline extends from Skellytown, Texas to our NGL fractionation and storage complex located in and near Mont Belvieu. Mixed NGLs from production fields located in 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. In addition, the Texas Express Pipeline transports mixed NGLs gathered by the Texas Express Gathering System. Also, mixed NGLs originating from the Denver-Julesburg ("DJ") Basin in Colorado are transported to the Texas Express Pipeline using the Front Range Pipeline. Our 35% ownership interest in the Texas Express Pipeline is held indirectly through our equity method investment in Texas Express Pipeline LLC.

In May 2018, we conducted open commitment periods to determine shipper interest in expansions of the Texas Express Pipeline and Front Range Pipeline. Given the positive responses we received from shippers, we are proceeding with the expansions, which are expected to increase the transportation capacity of Texas Express Pipeline and Front Range Pipeline by 90 MBPD and 100 MBPD, respectively. The expansions are designed to facilitate growing production of NGLs from domestic shale basins, including the DJ Basin, by providing producers with flow assurance and greater access to Gulf Coast markets. We anticipate the expansion projects will be placed into service during the third quarter of 2019.

- The Skelly-Belvieu Pipeline transports mixed NGLs from Skellytown, Texas to Mont Belvieu. The Skelly-Belvieu Pipeline receives a significant quantity of NGLs through an interconnect with our Mid-America Pipeline System at Skellytown. Our 50% ownership interest in the Skelly-Belvieu Pipeline is held indirectly through our equity method investment in Skelly-Belvieu Pipeline Company, L.L.C.

- The Front Range Pipeline transports mixed NGLs from natural gas processing plants located in the DJ Basin in Colorado to an interconnect with our Texas Express Pipeline, Mid-America Pipeline System and other third party facilities located at Skellytown, Texas. Our 33.3% ownership interest in the Front Range Pipeline is held indirectly through our equity method investment in Front Range Pipeline LLC. As previously mentioned, we are in the process of expanding the transportation capacity of the Front Range Pipeline by 100 MBPD.

- The Aegis Ethane Pipeline ("Aegis") delivers purity ethane to petrochemical facilities located along the southeast Texas and Louisiana Gulf Coast. Aegis, when combined with a portion of our South Texas NGL Pipeline System, forms an ethane header system stretching from Corpus Christi, Texas to the Mississippi River in Louisiana.

- The Houston Ship Channel Pipeline System connects our Mont Belvieu area assets to our marine terminals on the Houston Ship Channel and to area petrochemical plants, refineries and other pipelines.

- The Rio Grande Pipeline transports mixed NGLs from near Odessa, Texas to a pipeline interconnect at the Mexican border south of El Paso, Texas. We own a 70% consolidated interest in the Rio Grande Pipeline through our majority owned subsidiary, Rio Grande Pipeline Company.

- The Panola Pipeline transports mixed NGLs from injection points near Carthage, Texas to the Mont Belvieu hub and supports the Haynesville and Cotton Valley oil and gas production areas. We own a 55% consolidated interest in the Panola Pipeline through our majority owned subsidiary, Panola Pipeline Company, LLC.

- 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. Our 50% 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").

§ The Texas Express Gathering System is comprised of two gathering systems, Elk City and North Texas, that deliver mixed NGLs to the Texas Express Pipeline. Our 45% ownership interest in the Texas Express Gathering System is held indirectly through our equity method investment in Texas Express Gathering LLC.

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

Shin Oak NGL Pipeline. In April 2017, we announced plans to build the 658-mile Shin Oak NGL Pipeline to transport growing NGL production from the Permian Basin to our NGL fractionation and storage complex located at the Mont Belvieu hub. In February 2019, the 24-inch diameter mainline segment from Orla, Texas to Mont Belvieu was placed into limited commercial service with an initial transportation capacity of 250 MBPD. Completion of the related 20-inch diameter Waha lateral is scheduled for the second quarter of 2019. Supported by long-term customer commitments, the Shin Oak NGL Pipeline will ultimately provide up to 550 MBPD of transportation capacity, which is expected to be available in the fourth quarter of 2019.

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

In conjunction with the long-term NGL supply agreement, we granted Apache an option to acquire up to a 33% equity interest in our subsidiary that owns the Shin Oak NGL Pipeline. In November 2018, Apache contributed this option to Altus Midstream Company, which is a majority-owned subsidiary of Apache. The option is exercisable within sixty days after certain completion milestones are met (as defined in the underlying agreements), which we expect to occur in the second quarter of 2019.

NGL fractionation

We own or have interests in 16 NGL fractionators located in Texas and Louisiana that separate mixed NGL streams into purity NGL products for third party customers and also our NGL marketing activities. 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.

The following table presents selected information regarding our NGL fractionation facilities at February 1, 2019:

Description of Asset	Location	Ownership Interest	Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
NGL fractionation facilities:				
Mont Belvieu complex:				
Fracs I, II and III	Texas	75.0% (2)	189	245
Fracs IV, V, VI and IX	Texas	100.0%	345	345
Fracs VII and VIII	Texas	75.0% (3)	128	170
Total Mont Belvieu complex			662	760
Shoup and Armstrong	Texas	100.0%	93	93
Hobbs	Texas	100.0%	75	75
Norco	Louisiana	100.0%	75	75
Promix	Louisiana	50.0%	73	145
Tebone	Louisiana	100.0%	30	30
Baton Rouge	Louisiana	32.2%	19	60
Total			1,027	1,238

(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) We proportionately consolidate a 75% undivided interest in these fractionators.
(3) We own a 75% consolidated equity interest in NGL fractionators VII and VIII through our majority owned subsidiary, Enterprise EF78 LLC.

On a weighted-average basis, overall utilization rates for our NGL fractionators were 94.0%, 91.0% and 90.2% during the years ended December 31, 2018, 2017 and 2016, respectively.

The following information describes our NGL fractionators, all of which we operate.

§ The Mont Belvieu NGL fractionation complex includes fractionators located either in Mont Belvieu or in surrounding areas of Chambers County, Texas. This complex processes mixed NGLs from several major NGL supply basins in North America, including the Permian Basin, Rocky Mountains, Eagle Ford Shale, Mid-Continent and San Juan Basin. In addition, the Mont Belvieu NGL fractionation complex features connectivity to our network of NGL supply and distribution pipelines, approximately 130 MMBbls of underground salt dome storage capacity, along with access to international markets through our marine terminals located on the Houston Ship Channel.

Demand for NGL fractionation capacity continues to expand as producers in domestic shale plays such as the Permian Basin, Eagle Ford Shale and DJ Basin seek market access and end users require supply assurance. In May 2018, we placed our ninth NGL fractionator, which is located in Chambers County, Texas, into service. The new fractionator has a capacity of 90 MBPD, which increased total NGL fractionation capacity at our Mont Belvieu complex to 760 MBPD. In addition, we announced in November 2018 plans to construct a new NGL fractionation facility in Chambers County, Texas adjacent to our existing Mont Belvieu NGL fractionation complex. The new facility will consist of two fractionation trains capable of processing a combined 300 MBPD of NGLs. The first of the two fractionation trains will have a nameplate capacity of 150 MBPD and is scheduled to be completed and begin service in the fourth quarter of 2019. The second of these fractionation trains will also have a nameplate capacity of 150

MBPD, and is scheduled to begin service in the first half of 2020.

§ The Shoup and Armstrong NGL fractionators in South Texas process mixed NGLs supplied by regional 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 the Mont Belvieu hub using our South Texas NGL Pipeline System.

In November 2018, we announced a project to optimize our Shoup NGL fractionator by expanding and repurposing a portion of our South Texas pipelines. The project will entail the construction of approximately 21 miles of new pipeline along with the conversion of approximately 65 miles of existing natural gas pipelines to NGL service, which will allow us to supply Shoup with an additional 25 MBPD of NGL volumes. The expanded pipeline capacity is expected to be available in the third quarter of 2019.

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§ The Hobbs NGL fractionator serves NGL producers in West Texas, New Mexico and Colorado. This 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 NGL Pipeline, thus providing customers access to both the Mont Belvieu and Conway hubs.

§ The Norco NGL fractionator receives mixed NGLs 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 plants.

§ The Promix NGL fractionator receives mixed NGLs from natural gas processing plants located in south Louisiana and along the Mississippi Gulf Coast, including our Neptune and Pascagoula plants. The Promix NGL fractionation facility includes three NGL storage caverns and a barge dock that are integral to its operations. Our 50% ownership interest in the Promix fractionator is held indirectly through our equity method investment in Promix.

§ The Tebone NGL fractionator, which was restarted in February 2019 in light of regional demand for fractionation services, receives mixed NGLs from our Louisiana natural gas processing plants, as well as our Mont Belvieu storage complex. The resumption of service at our Tebone fractionator complements our operations at the Norco and Promix NGL fractionators and provides us with another processing option for mixed NGLs delivered to Mont Belvieu.

§ The Baton Rouge NGL fractionator receives mixed NGLs from natural gas processing plants located in Alabama, Mississippi and south Louisiana. This facility includes a leased NGL storage cavern. Our 32.2% ownership interest in the Baton Rouge fractionator is held indirectly through our equity method investment in Baton Rouge Fractionators LLC.

NGL and related product storage facilities

We utilize underground salt dome storage caverns and above-ground storage tanks to store mixed and purity NGLs, petrochemicals and related products that are 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, 2019:

Storage Capacity by Asset	Location	Ownership Interest	Net Usable Storage Capacity (MMBbls) (1)
Mont Belvieu storage complex	Texas	100.0%	129.8
Almeda and Markham (2)	Texas	Leased	12.4
Breaux Bridge, Anse La Butte and Sorrento (3)	Louisiana	100.0%	12.7
Petal (4)	Mississippi	100.0%	5.1
Hutchinson (5)	Kansas	100.0%	4.0
Others (6)	Various	Various	14.2
Total			178.2

(1) Net usable storage capacity is based on our ownership interest or contractual right-of-use.

(2) These storage facilities are used in connection with our South Texas NGL Pipeline System.
(3) These storage facilities are used in connection with our Louisiana Pipeline System.
(4) This storage facility is used in connection with our Dixie Pipeline.
(5) This storage facility is used in connection with our Mid-America Pipeline System.
(6) Primarily consists of operational storage capacity for our major pipeline systems, including the Mid-America Pipeline System, Dixie Pipeline and TE Products Pipeline. We own substantially all of this storage capacity.

We operate substantially all of our NGL and related product storage facilities.

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Our largest underground storage facility is located at the Mont Belvieu hub in Chambers County, Texas. This facility consists of 38 underground salt dome caverns used to store and redeliver mixed and purity NGLs, petrochemicals and related products. This facility has an aggregate usable storage capacity of 129.8 MMBbls, a brine system with approximately 31 MMBbls of above-ground brine storage capacity and five wells used in brine production.

NGL marine 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.

The following information describes our Houston Ship Channel terminals, both of which we operate.

§ The Enterprise Hydrocarbons Terminal ("EHT") is located on the Houston Ship Channel and provides terminaling services to exporters, marketers, distributors, chemical companies and major integrated oil companies. EHT has extensive waterfront access consisting of seven deep-water ship docks and one barge dock. 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 enables us to handle larger vessels than our competitors because our waterfront has fewer draft and beam (width) restrictions. The size and structure of our waterfront allows us to receive and unload products for our customers and provide terminaling and dock services.

EHT can load refrigerated cargoes of low-ethane propane and/or butane (collectively referred to as LPG) onto multiple tanker vessels simultaneously. 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 production and for power generation and heating purposes. LPG loading volumes at EHT averaged 445 MBPD, 424 MBPD and 420 MBPD during the years ended December 31, 2018, 2017 and 2016, respectively.

Our current loading capacity for LPG is approximately 545 MBPD. In September 2018, we announced a project to increase LPG loading capacity at EHT by 175 MBPD, or approximately 5 MMBbls per month. The expansion will bring our total LPG export capacity at EHT to 720 MBPD, or approximately 21 MMBbls per month. Upon completion of this expansion project, EHT will have the capability to load up to six Very Large Gas Carrier ("VLGC") vessels simultaneously, while maintaining the option to switch between loading propane and butane. Once operational, the expansion will allow EHT to load a single VLGC in less than 24 hours, creating greater efficiencies and cost savings for our customers. The incremental loading capacity is expected to be available in the third quarter of 2019.

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, 2018, the destination markets were as follows: 55% to Asia; 18% to North America and the Caribbean; 13% to Central and South America; 12% to Europe and Africa; and 2% 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: 51% for North America and the Caribbean; 43% for Asia; 34% for Central and South America; 21% for Europe and Africa; and 10% for other destinations, including Australia and the Middle East.

EHT also includes an NGL import terminal. 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.

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

§ The Morgan's Point Ethane Export Terminal, located on the Houston Ship Channel, 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. The terminal supports domestic production of U.S. ethane from shale plays by providing the global petrochemical industry with access to a low-cost feedstock option and opportunities for supply diversification. We estimate that U.S. Gulf Coast ethane supply currently exceeds U.S. demand by approximately 300 MBPD and could exceed demand by approximately 1 MMBPD in 2024, after considering estimated incremental demand from third party ethylene production facilities that are being constructed along 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.

Ethane volumes handled by the terminal are sourced from our Mont Belvieu NGL fractionation and storage complex. Ethane loading volumes at the terminal averaged 146 MBPD, 90 MBPD and 15 MBPD during the years ended December 31, 2018, 2017 and 2016, respectively. The terminal was placed into commercial service in August 2016.

Crude Oil Pipelines & Services Segment

Our Crude Oil Pipelines & Services business segment currently includes approximately 5,300 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, Items 1 and 2 discussion for additional information regarding governmental oversight of our crude oil pipelines and storage facilities.

The following table presents selected information regarding our crude oil pipelines and related operations at February 1, 2019:

Description of Asset	Location(s)	Our Ownership Interest	Operational Storage Capacity (MMBbls) (2)	Pipeline Length (Miles)
Seaway Pipeline (1)	Texas, Oklahoma	50.0%	8.8	1,271
West Texas System (1)	Texas, New Mexico	100.0%	0.9	1,034
South Texas Crude Oil Pipeline System	Texas	100.0%	3.8	648
Basin Pipeline (1)	Texas, New Mexico, Oklahoma	13.0% (3)	6.0	618
EFS Midstream System	Texas	100.0%	0.3	485
Midland-to-ECHO 2 Pipeline System	Texas	100.0%	--	440
Midland-to-ECHO 1 Pipeline System	Texas	80.0%	3.9	418
Eagle Ford Crude Oil Pipeline System	Texas	50.0%	4.5	378
Total			28.2	5,292

(1) Transportation services provided by these liquids pipelines are regulated, in whole or part, by federal governmental agencies.
(2) Operational storage capacity amounts presented on a gross basis.
(3) We proportionately consolidate our 13% undivided interest in the Basin Pipeline.

In October 2018, we sold our Red River System and associated crude oil linefill for $134.9 million. For additional information regarding this sale, see Note 4 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

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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. In the aggregate, net throughput volumes for these pipelines were 2,000 MBPD, 1,820 MBPD and 1,388 MBPD during the years ended December 31, 2018, 2017 and 2016, respectively.

The following information describes 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. Our 50% ownership interest in the Seaway Pipeline is held indirectly through our equity method investment in Seaway Crude Pipeline Company LLC (“Seaway”). The Seaway Pipeline is comprised of the Longhaul System, the Freeport System and the Texas City System. The Cushing hub is an 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 approximately 500-mile, 30-inch diameter pipelines (Seaway I and the Seaway Loop) that provide north-to-south transportation of crude oil from the Cushing hub to Seaway’s Jones Creek terminal located near Freeport, Texas. The aggregate transportation capacity of the Longhaul System is approximately 950 MBPD, depending on the type and mix of crude oil being transported and other variables. The Jones Creek terminal is connected by pipeline to our Enterprise Crude Houston (“ECHO”) storage terminal, which enables Seaway to serve a variety of customers along the upper Texas Gulf Coast including the Beaumont/Port Arthur area.

The Freeport System consists of a marine terminal that facilitates both crude oil imports and exports, along with pipelines that transport crude oil to and from Freeport, Texas and the Jones Creek terminal.

The Texas City System consists of a marine terminal and storage tanks, various pipelines and related infrastructure used to transport crude oil to refineries in the Texas City, Texas area and to and from terminals in the Galena Park, Texas area, our 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 pipeline transportation capacity of the Freeport System and Texas City System is approximately 480 MBPD and 800 MBPD, respectively. Seaway’s Texas City marine terminal features two docks, a 45-foot draft, an overall length of 1,125 feet, a 200-foot beam (width) and the capacity to load crude oil at a rate of 35,000 barrels per hour.

In June 2018, our crude oil marketing group commenced the loading of Very Large Crude Carrier (“VLCC”) tankers using Seaway’s Texas City terminal in combination with lightering operations in the Gulf of Mexico.

- The West Texas System connects crude oil gathering systems in West Texas and southeast New Mexico to our terminal facility located in Midland, Texas. The West Texas System, including the recently completed Loving County pipeline, is a key part of our strategic aggregation program designed to support Permian Basin producers. The Loving County pipeline, which was completed in July 2018, can currently transport 200 MBPD of crude oil and condensate from various points in New Mexico and West Texas to our Midland, Texas crude oil terminal; however, we expect to complete an expansion project in March 2019 that will increase its transportation capacity up to 350 MBPD. At Midland, shippers will have access to storage and terminal services, as well as connectivity to multiple transportation alternatives such as trucking and pipeline infrastructure that offer access to various downstream markets, including the Gulf Coast.

- The South Texas Crude Oil Pipeline System transports crude oil and condensate originating in South Texas to customers in the Houston area. This system includes storage terminal assets located at Sealy, Texas. The South

Texas Crude Oil Pipeline System also includes our Rancho II pipeline, which extends 89-miles from the Sealy terminal to our ECHO terminal. From ECHO, we have connectivity to refinery customers and our marine terminals.

§ The Basin Pipeline transports crude oil from the Permian Basin in West Texas and southern New Mexico to the Cushing hub.

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§ 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 485 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.

§ The Midland-to-ECHO 2 Pipeline System, which began limited commercial service in February 2019, provides us with approximately 200 MBPD of incremental crude oil transportation capacity from the Permian Basin to markets in the Houston area. The pipeline is expected to enter full commercial service in April 2019. The pipeline originates at our Midland terminal and extends 440 miles to our Sealy storage terminal, with volumes arriving at Sealy transported to our ECHO terminal using the Rancho II pipeline, which is a component of our South Texas Crude Oil Pipeline System.

We converted a portion of our Seminole NGL Pipeline system from NGL service to crude oil service to create the Midland-to-Sealy segment of this pipeline system. The conversion is supported by a 10.75-year transportation contract with firm demand fees. We have the ability to convert this pipeline back to NGL service should market and physical takeaway conditions warrant.

§ The Midland-to-ECHO 1 Pipeline System, which became fully operational in the second quarter of 2018, provides Permian Basin producers with the ability to transport multiple grades of crude oil, including WTI, WTI light sweet crude oil (“WTI Light”), West Texas Sour, and condensate, to Gulf Coast markets. As a result of operating enhancements and supplementary infrastructure, the pipeline’s transportation capacity is expected to increase to 620 MBPD beginning in March 2019.

The Midland-to-ECHO 1 Pipeline System originates at our Midland terminal and extends 418 miles to our Sealy storage terminal. Volumes arriving at Sealy are then transported to our ECHO terminal using the Rancho II pipeline. Using the ECHO terminal, shippers on the Midland-to-ECHO 1 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. The Midland-to-ECHO 1 Pipeline System includes certain storage assets located at Sealy, Texas.

The majority of the Midland-to-ECHO 1 Pipeline System is owned by Whitethorn Pipeline Company LLC (“Whitethorn”), in which we own an 80% equity interest. In June 2018, an affiliate of Western Gas Partners, LP acquired a 20% equity interest in Whitethorn for $189.6 million in cash.

§ 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 interconnects with our South Texas Crude Oil Pipeline System in Wilson County, Texas and a marine terminal located in Corpus Christi that is under construction. Our 50% ownership interest in the Eagle Ford Crude Oil Pipeline System is held indirectly through our equity method investment in Eagle Ford Pipeline LLC.

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 terminals 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.

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The following table presents selected information regarding our crude oil terminals at February 1, 2019:

Description of Asset	Location(s)	Ownership Interest	Number of Marine Docks	Number of Above-Ground Tanks in Service	Storage Capacity (MMBbls)
EHT (crude oil)	Texas	100.0%	7 deep-water ship; 1 barge	84	24.0
ECHO (1)	Texas	100.0%	n/a	15	6.4
Beaumont Marine West	Texas	100.0%	4 deep-water ship; 2 barge	12	4.1
Cushing	Oklahoma	100.0%	n/a	20	3.5
Midland	Texas	100.0%	n/a	12	2.5
Total				143	40.5

(1) Number of tanks and storage capacity excludes three tanks that are used in the operation of our Midland-to-ECHO 1 Pipeline System and two tanks owned by Seaway.

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

§ The EHT crude oil terminal is one of the largest such facilities on the Gulf Coast and part of our EHT complex, which is located on the Houston Ship Channel and features extensive waterfront access consisting of seven deep-water ship docks and a barge dock. As noted previously, 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.

§ 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. ECHO also has connections to marine terminals, including EHT, that provide access to any refinery on the U.S. Gulf Coast and international markets.

In September 2018, the CME Group, a leading derivatives marketplace, announced that suppliers, refiners and end users of U.S. crude oil have a new way to price and hedge WTI in Houston, Texas. Participants will have the flexibility to make or take delivery of WTI at our ECHO terminal, EHT or pipeline interconnect at Genoa Junction. The new futures contracts received regulatory approval in October 2018 and are listed with and subject to the rules of the NYMEX, beginning with the January 2019 contract month.

§ The Beaumont Marine West terminal is located on the Neches River near Beaumont, Texas. This terminal includes four deep-water docks and two barge docks that facilitate the exporting and importing of crude oil and related products.

§ The Cushing terminal is located at the Cushing hub in Oklahoma and provides crude oil storage, pumpover and trade documentation services. This terminal is one of the origination points for our Seaway Pipeline.

§ The Midland terminal provides crude oil storage, pumpover and trade documentation services. The Midland terminal is the origination point for our Midland-to-ECHO 1 and 2 Pipeline Systems.

Texas Gulf Coast Offshore Oil Terminal. We are in the planning stage of developing a crude oil export terminal located offshore along the Texas Gulf Coast. The terminal would be capable of fully loading VLCC marine tankers, which have capacities of approximately 2 MMBbls and provide the most efficient and cost-effective solution to export crude oil to the largest international markets in Asia and Europe. We started front-end engineering and design work for the terminal in 2018 and filed our application for regulatory permitting with the Maritime Administration (“MARAD”) in January 2019. Based on initial designs, the project would include onshore and offshore facilities capable of exporting crude oil at approximately 85,000 barrels per hour. A final investment decision for the project will be subject to the execution of long-term customer contracts and receiving state and federal permits.

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Corpus Christi Marine Terminal. We are joint owners of a marine crude oil terminal being constructed in Corpus Christi, Texas that will be capable of loading ocean-going vessels with either crude oil or condensate. Initial storage capacity of the terminal will be approximately 1.2 MMBbls. The facility will have access to production from both the Eagle Ford Shale and the Permian Basin through a connection with our Eagle Ford Crude Oil Pipeline System. The Corpus Christi marine terminal is expected to be placed into commercial service in the second quarter of 2019. Our 50% ownership interest in the terminal is held indirectly through our equity method investment in EF Terminals Corpus Christi LLC.

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 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 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 360 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 currently includes approximately 19,700 miles of natural gas pipeline systems that provide for the gathering, treating 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, treat and transport natural gas from producing regions including 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. Our natural gas pipelines redeliver the natural gas to processing facilities, electric generation plants, local gas distribution companies, industrial and 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 gathered, treated, 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, Items 1 and 2 discussion for additional information regarding governmental oversight of our natural gas pipelines.

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The following table presents selected information regarding our natural gas pipelines and related infrastructure at February 1, 2019:

				Net Capacity (1)		
Description of Asset	Location(s)	Ownership Interest	Pipeline Length (Miles)	Pipeline Capacity (MMcf/d)	Natural Gas Treating (MMcf/d)	Usable Storage (Bcf)
Texas Intrastate System (2)	Texas	Various	6,944	7,345	80	12.9
Acadian Gas System (2)	Louisiana	100.0%	1,312	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%	6,073	1,750	440	--
Permian Basin Gathering System	Texas, New Mexico	100.0%	1,687	1,575	150	--
White River Hub (3)	Colorado	50.0%	10	1,500	--	--
Haynesville Gathering System	Louisiana, Texas	100.0%	357	1,300	810	--
BTA Gathering System(4)	Texas	100.0%	783	1,000	160	--
Fairplay Gathering System (4)	Texas	100.0% (5)	273	285	--	--
Indian Springs Gathering System (4)	Texas	80.0% (6)	145	160	--	--
Delmita Gathering System	Texas	100.0%	204	145	--	--
South Texas Gathering System	Texas	100.0%	518	143	--	--
Old Ocean Pipeline	Texas	50.0%	240	80	--	--
Big Thicket Gathering System	Texas	100.0%	250	60	--	--
Central Treating Facility	Colorado	100.0%	--	--	200	--
Total			19,747	22,603	1,840	14.2

(1) Net capacity amounts are based on our ownership interest or contractual right-of-use.
(2) Transportation services provided by these pipeline systems, in whole or part, are regulated by both federal and state governmental agencies.
(3) Services provided by the White River Hub are regulated by federal governmental agencies.
(4) Transportation services provided by these systems are regulated in part by state governmental agencies.
(5) This system includes approximately 52 miles of pipeline held under an operating lease.
(6) 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 58.3%, 57.1% and 57.4% during the years ended December 31, 2018, 2017 and 2016, 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 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 6,319-mile Enterprise Texas pipeline system and the 625-mile Channel pipeline system. The Texas Intrastate System gathers, transports and stores natural gas from supply basins in Texas including the Permian Basin and Eagle Ford and Barnett Shales for delivery to local gas distribution companies, electric utility plants and industrial and municipal consumers. The system is also connected to regional natural gas processing plants and other intrastate and interstate pipelines. The Texas Intrastate System serves a number of commercial markets in Texas, including Corpus Christi, San Antonio/Austin, Beaumont/Orange and Houston, including the Houston Ship Channel industrial market.

We proportionately consolidate our undivided interests, which range from 22% to 80%, in 1,471 miles of pipeline. The Texas Intrastate System also includes our Wilson natural gas storage facility, which consists of a network of leased and owned underground salt dome storage caverns located in Wharton County, Texas with an aggregate 12.9 Bcf of usable storage capacity. Four of these caverns, comprising 6.9 Bcf of usable capacity, are held under an operating lease. The remainder of our Texas Intrastate System is wholly owned.

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§ The Acadian Gas System transports, stores and markets natural gas in Louisiana. The Acadian Gas System is comprised of the 582-mile Cypress pipeline, 429-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 utility 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 facility.

§ The Piceance Basin Gathering System gathers natural gas produced from the Piceance Basin in northwestern Colorado to our Meeker natural gas processing plant.

§ The San Juan Gathering System gathers and treats natural gas produced from the San Juan Basin in northern New Mexico and southern Colorado and delivers the natural gas either directly into interstate pipelines (if dry natural gas) or to regional natural gas plants, including our Chaco facility, for further processing (if rich natural gas) prior to being transported on interstate pipelines.

§ The Permian Basin Gathering System is comprised of the 982-mile Carlsbad pipeline system, the 671-mile Waha pipeline system and the 34-mile Orla pipeline system. The Permian Basin Gathering System gathers natural gas from the Permian Basin for delivery to regional natural gas processing plants, including our Chaparral, Carlsbad, South Eddy, Waha and Orla plants, and delivers residue and treated natural gas into our Texas Intrastate System and third party pipelines.

§ The White River Hub is a natural gas hub facility serving producers in the Piceance Basin. The facility enables producers to access six interstate natural gas pipelines and has a gross throughput capacity of 3 Bcf/d of natural gas. Our 50% ownership interest in White River Hub is held indirectly through our equity method investment in White River Hub, LLC.

§ The Haynesville Gathering System consists of the 214-mile State Line gathering system, the 73-mile Southeast Mansfield gathering system, and the 70-mile Southeast Stanley gathering system. The Haynesville Gathering System gathers and treats 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, which is located in East Texas, gathers and treats natural gas from the Haynesville Shale and Bossier, Cotton Valley and Travis Peak formations. We acquired this system, along with our Panola and Fairway natural gas processing plants, in April 2017 for $191.4 million. 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 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.

§ The Indian Springs Gathering System, along with the Big Thicket Gathering System, gather natural gas from the Woodbine, Wilcox and Yegua production areas in East Texas.

§

The Delmita Gathering System gathers natural gas from the Frio-Vicksburg formation in South Texas for delivery to our Delmita natural gas processing plant.

§ The South Texas Gathering System gathers natural gas from the Olmos and Wilcox formations for delivery into our Texas Intrastate System, which delivers the natural gas to our South Texas natural gas processing plants.

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- The Old Ocean Pipeline transports natural gas from an injection point on our Texas Intrastate System near Maypearl, Texas for delivery to a pipeline interconnect at Sweeny, Texas. In May 2018, we announced the formation of a 50/50 joint venture with Energy Transfer Partners, L.P. ("ETP") to resume full service on the Old Ocean natural gas pipeline owned by ETP. The 24-inch diameter Old Ocean Pipeline originates in Maypearl, Texas in Ellis County and extends south approximately 240 miles to Sweeny, Texas in Brazoria County. ETP serves as operator of the pipeline, which has a gross natural gas transportation capacity of 160 MMcf/d. Repairs were completed on the pipeline, and it entered full service in January 2019.

In addition, both parties expanded their jointly owned North Texas 36-inch diameter natural gas pipeline, which is a component of our Texas Intrastate System. The expansion project was completed in January 2019 and provides us with additional natural gas takeaway capacity of 150 MMcf/d from West Texas, including deliveries into the Old Ocean Pipeline. The resumption of full service on the Old Ocean Pipeline and expansion of the North Texas Pipeline provide producers with additional takeaway capacity to accommodate growing natural gas production from the Delaware and Midland Basins.

- The Central Treating Facility is located in Rio Blanco County, Colorado and serves producers in the Piceance Basin. Natural gas delivered to the 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 utility 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 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 currently includes: (i) propylene production facilities, which include propylene fractionation units and a propane dehydrogenation ("PDH") facility, approximately 800 miles of pipelines, and associated marketing operations; (ii) a butane isomerization complex and related deisobutanizer ("DIB") operations, along with approximately 70 miles of associated pipelines; (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. This segment will also include our ethylene export terminal and related operations.

Propylene production and related operations

Our propylene production and related operations include seven propylene fractionation (or splitter) units, a PDH facility, approximately 800 miles of related pipelines, marine export dock infrastructure, and associated marketing activities.

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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 2018, global demand for propylene (PGP and CGP combined) was estimated at 108 million tons. Propylene fractionation units separate RGP, which is a mixture of propane and propylene, into either PGP or CGP. The PDH facility produces PGP using propane feedstocks. 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, 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 PDH facility entered full service in April 2018. The facility, which is located in Chambers County, Texas at our Mont Belvieu complex, 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 consumes 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 was underwritten by long-term, fee-based contracts that feature minimum volume commitments.

To the extent we fractionate RGP for customers, we enter into toll processing arrangements. In our petrochemical marketing activities, we purchase RGP on the open market for fractionation at our splitter units and sell the resulting PGP to customers at market-based prices. The results of this marketing activity are primarily dependent upon the difference, or spread, between the sales prices of the PGP and the associated purchase and other costs, including the costs attributable to use of our propylene production assets and related infrastructure. 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 purchase of 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.

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. In order to meet the growing international demand for PGP, this business also includes export assets located at EHT 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 production facilities at February 1, 2019:

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
PDH facility:					
Mont Belvieu	Texas	100.0%		25	25

(1) We proportionately consolidate a 66.7% undivided interest in three of the propylene splitters, 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 propylene fractionation units and PDH facility located at the Mont Belvieu hub and CGP at our BRPC facility located in Baton Rouge, Louisiana. On a weighted-average basis, the overall utilization rate of our propylene production facilities was approximately 86.7%, 89.9% and 81.9% during the years ended December 31, 2018, 2017 and 2016, respectively.

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The following table presents selected information regarding our propylene pipelines at February 1, 2019:

Description of Asset	Location(s)	Ownership Interest		Length (Miles)
Lou-Tex Propylene Pipeline	Texas, Louisiana	100.0%		263
Texas City RGP Gathering System	Texas	100.0%		167
North Dean Pipeline System	Texas	100.0%		157
Propylene Splitter PGP Distribution System	Texas	100.0%		82
Louisiana RGP Gathering System	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				794

(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 125 MBPD, 106 MBPD and 121 MBPD during the years ended December 31, 2018, 2017 and 2016, respectively.

The Lou-Tex Propylene pipeline is used to transport CGP from Sorrento, Louisiana to Mont Belvieu. 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.

With the exception of the Lake Charles PGP Pipeline in Louisiana, we operate all of our propylene production assets and related pipelines.

Isomerization and related operations

We own and operate three isomerization units at our Mont Belvieu complex 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 the Mont Belvieu hub to Port Neches, Texas. We own and operate this pipeline system.

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 originating from NGL fractionation activities, imports and other sources into isobutane and normal butane. The operating flexibility provided by our multiple standalone DIBs enables us to capture market opportunities resulting from fluctuations in demand and prices for different types of butanes.

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%, 92.2% and 93.1% during the years ended December 31, 2018, 2017 and 2016, respectively.

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In January 2018, we announced plans to expand our butane isomerization facility by up to 30 MBPD of incremental capacity. The expansion is supported by long-term agreements to provide butane isomerization, storage and related pipeline services. We currently expect this project to be completed during the fourth quarter of 2021.

Octane enhancement and related operations

We own and operate an octane enhancement production facility located at our Mont Belvieu complex that is designed to produce isobutylene and either isooctane or methyl tertiary butyl ether ("MTBE"). The products produced by this facility are used by refiners to increase octane values in reformulated motor gasoline blends. 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 its combined isooctane, isobutylene and MTBE production volumes, which averaged 24 MBPD, 23 MBPD and 19 MBPD during the years ended December 31, 2018, 2017 and 2016, respectively.

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 related product storage capacity. The primary feedstock for this plant, an isobutane/isobutylene mix, is produced by our octane enhancement facility. HPIB is used in the production 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 88.9%, 75.9% and 58.4% for the years ended December 31, 2018, 2017 and 2016, 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 and the associated feedstock purchase costs and other operating expenses.

Isobutane Dehydrogenation Unit. In January 2017, we announced plans to construct an isobutane dehydrogenation ("iBDH") unit at our Mont Belvieu complex that is expected to have the capability to produce 425,000 tons of isobutylene per year. The project, which is underwritten by long-term customer contracts, 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 such as 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 iBDH plant will increase our production of high purity and low purity isobutylene, both of which are used as feedstocks to manufacture lubricants, rubber products and alkylate for gasoline blendstocks, as well as MTBE for export.

Refined products services

Our refined products services business includes refined products pipelines aggregating approximately 4,100 miles, terminals and associated marketing activities.

Refined products pipelines. We own and operate the TE Products Pipeline, which is a 3,278-mile pipeline system comprised of 2,953 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.

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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. See “Regulatory Matters” within this Part I, Items 1 and 2 discussion for additional information regarding governmental oversight of our liquids pipelines, including tariffs charged for transportation services.

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 years indicated:

	For the Year Ended December 31,		
	2018	2017	2016
Refined products transportation (MBPD)	456	456	474
Petrochemical transportation (MBPD)	148	156	164
NGL transportation (MBPD)	71	57	55

The TE Products Pipeline system includes five non-regulated refined products truck terminals and 18.5 MMBbls of aggregate storage capacity.

We also 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). Although the Centennial Pipeline is currently idle, we continue to evaluate potential projects with our joint venture partner that could repurpose the line.

Refined products marine terminals. We own and operate marine terminals located on the Neches River near Beaumont, Texas that handle refined products along with crude oil. Our Beaumont facilities include five deep-water ship docks, three barge docks and access to approximately 7.8 MMBbls of aggregate refined products storage capacity.

We also handle refined products at EHT 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 64 tow boats and 148 tank barges 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.

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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 93.5%, 86.3% and 85.2% during the years ended December 31, 2018, 2017 and 2016, 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, Items 1 and 2 discussion.

Ethylene export terminal and related operations

We are constructing an ethylene export terminal located at Morgan's Point on the Houston Ship Channel. When completed, the terminal, which we will operate, is expected to have an export capacity of approximately 2.2 billion pounds of ethylene per year, with loading rates of 2.2 million pounds per hour, and feature on-site refrigerated storage for 66 million pounds of ethylene. The project, which is underwritten by long-term customer commitments, is expected to begin limited commercial service in the fourth quarter of 2019, with full operations expected in the fourth quarter of 2020 once certain refrigeration assets are complete. We own a 50% equity interest in Enterprise Navigator Ethylene Terminal LLC, which owns the export facility.

In the second quarter of 2019, we expect to complete a project at our Mont Belvieu storage complex that repurposes a large, high-capacity ethane storage well into ethylene service. The new 5.3 MMBbl ethylene storage cavern will feature an injection/withdrawal rate of approximately 210,000 pounds per hour (or approximately 2,000 barrels per hour) and be 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 new high-capacity well, which provides us with significant connection opportunities.

In further support of our ethylene capabilities, we are building a 24-mile ethylene pipeline extending from our Mont Belvieu complex to Bayport, Texas. The new pipeline will have the potential to connect both producing and consuming customers located south of the Houston Ship Channel to our ethylene storage facility in Mont Belvieu. The pipeline between our Mont Belvieu complex and Morgan's Point terminal is expected to be completed in 2019, with the remaining sections completed in 2020.

Regulatory Matters

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

Environmental, Safety and Conservation

The safe operation of our pipelines and other assets is a top priority. 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 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 similar state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures of employees.

Certain of our facilities are also 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 certain chemicals, flammable gases or liquids at or above a specified threshold (as defined in the regulations). In addition, we are subject to 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

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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 as 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. The DOT regulates natural gas and hazardous liquids pipelines through its Pipeline and Hazardous Materials Safety Administration ("PHMSA"). We believe we are in material compliance with DOT regulations.

We are also 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. These regulations require 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 pipeline segments in HCAs 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 currently provides for penalties involving non-compliance with DOT regulations of \$0.2 million for a single violation and a maximum fine for the most serious pipeline safety violations (e.g., those violations resulting in deaths, injuries or major environmental harm) of \$2.1 million per incident. In addition, the Pipeline Safety Act includes additional safety requirements for newly constructed pipelines.

In June 2016, 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. The SAFE PIPES Act extends the PHMSA's statutory mandate through 2019 and 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; 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.

DOT regulations have incorporated by reference American Petroleum Institute Standard 653 ("API 653") as the industry standard for the inspection, repair, alteration and reconstruction of above-ground storage tanks. API 653 requires that above-ground storage tanks undergo regularly scheduled maintenance, which may result in significant and unanticipated expenditures for repairs or upgrades that are deemed necessary to ensure the continued safe and reliable operation of such tanks.

PHMSA has issued proposed new or revised regulations under either the Pipeline Safety Act or the SAFE PIPES Act that may impact our pipelines. The proposed new or revised regulations for hazardous liquid pipelines include: (i) extending the reporting requirements to all hazardous liquid gravity and gathering lines; (ii) requiring inspections of pipelines in areas affected by extreme weather; (iii) requiring periodic inline integrity assessments of hazardous liquid
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pipelines in all locations; (iv) modifying the provisions for making pipeline repairs; (v) requiring all pipelines subject to integrity management requirements be capable of accommodating inline inspection tools within 20 years, with certain exceptions; and (vi) clarifying of other regulations to improve compliance. The notice regarding these regulations was issued in October 2015 and the final rule remains pending.

In March 2016, the PHMSA issued proposed new safety regulations for natural gas transmission pipelines that broaden the scope of safety coverage in several ways, including but not limited to: (i) 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; (ii) adding new assessment and revising repair criteria for pipeline segments in HCAs and establishing repair criteria for pipelines that are outside of HCAs; (iii) expanding the scope of the regulations to include pipelines located in areas of Medium Consequence Areas ("MCAs"); (iv) adding a requirement to test pipelines built before 1970, which are currently exempt from certain pipeline safety requirements; (v) modifying the way that pipeline operators secure and inspect transmission pipeline infrastructure following extreme weather events; (vi) clarifying requirements for conducting risk assessment associated with integrity management activities; (vii) expanding mandatory data collection and integration requirements associated with integrity management activities, including data validation; (viii) requiring new safety features for pipeline "pig" launchers and receivers; and (ix) requiring a systematic approach to verify a pipeline's maximum allowable operating pressure and requiring operators to report maximum allowable operating pressure exceedances. A final rule regarding these proposals remains pending.

PHMSA has also issued a final rule, which became effective in January 2019, that amends pipeline safety regulations covering the types, design, and installation of plastic materials that can be used to transport natural gas. The new rule permits the use of PVC pipe, adopts a variety of applicable industry standards, and revises regulations related to storage and handling, component design, valve design, standard fittings, and pipe testing associated with the use of plastic pipe.

In response to the SAFE PIPES Act, PHMSA issued an interim final rule adopting federal safety regulations and reporting requirements for underground natural gas storage facilities in December 2016. Petitions for review of the interim final rule are pending at the U.S. Court of Appeals for the Fifth Circuit, which is holding the proceeding in abeyance. In June 2017, PHMSA partially stayed enforcement of the interim rule's new safety standards until one year after publication of the final rule.

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 may result in us incurring significant and unanticipated expenditures to comply with such standards. 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; the National Historic Preservation 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.

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We believe our operations are in material compliance with existing environmental and safety laws and regulations and that our compliance with such 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. 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 regulated, 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. These laws and regulations may also require that we (i) 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 levels of air emissions, (ii) obtain and strictly comply with the requirements of air permits containing various emission and operational limitations, or (iii) utilize specific emission control technologies to limit emissions.

Increasingly, environmental groups are challenging requests to modify or renew permits and seeking to apply more stringent provisions on applicants. Our failure to comply with applicable requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, including enforcement actions, and our inability to renew or secure a needed modification to an existing permit 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 permits and approvals for air emissions.

Water Quality

The CWA and comparable state laws impose strict controls on the discharge of petroleum 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 into navigable waters or groundwater. Federal spill prevention control and countermeasure mandates 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 monitoring and other requirements. The CWA 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, deepwater ports, offshore production 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.

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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 historical operations, we believe any such contamination could be controlled or remedied; however, 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 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 NGL 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.

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The ICA prescribes that the 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 ending June 30, 2021, we are permitted to adjust the indexed rate ceiling annually by PPI plus 1.23%. 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 they otherwise would be above the indexed rate ceiling. Otherwise, a pipeline is permitted to increase its rates to the new ceiling. 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 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 administrative law judge 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. In May 2018, the FERC issued an order affirming the initial decision's finding that Seaway lacks market power in the applicable markets, thereby granting Seaway market-based rate authority.

In October 2016, the FERC sought comments regarding potential modifications to its policies for evaluating changes in oil pipeline indexed rates and the associated 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 (i) revenues that exceed the total cost-of-service by 15% for the two preceding years or (ii) the proposed increase in the rate index exceeds the percentage change in the pipeline's annual costs by 5%. The FERC is also considering requiring pipelines to file additional information for crude and refined product pipelines, non-contiguous systems and major pipeline systems. Comments on these proposals were filed with the FERC through March 2017; however, the FERC has taken no position at this time and we are unable to predict the outcome of this proceeding.

In March 2018, the FERC issued a Revised Policy Statement on the Treatment of Income Taxes (the "Revised Policy"). The Revised Policy reversed a 13-year old policy that permitted a pipeline owned by a master limited partnership ("MLP") to recover an income tax allowance ("ITA") in its cost-of-service rates, if it could demonstrate that the ultimate owners of the pipeline (i.e., the unitholders of the MLP) have an actual or potential income tax liability. In July 2018, the FERC, in an Order on Rehearing, decided to provide pipeline MLPs the opportunity to argue for inclusion of an ITA in cost-of-service rates on a case-by-case basis, as opposed to having no opportunity to recover an ITA. Two third parties filed petitions for review of the Revised Policy and Order on Rehearing in the D.C. Circuit in September 2018. We are unable to predict the outcome of these pending petitions for review.

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The Revised Policy and Order on Rehearing do not impact oil and liquids pipelines with market-based rate authority, or those that charge "settlement rates," and have no immediate effect on oil and liquid pipelines with rates set using the indexing methodology, given that the current index will remain in effect through June 30, 2021. However, following issuance of the Revised Policy, the FERC now requires oil and liquids pipelines owned by MLPs to remove the ITA from their cost-of-service reporting in FERC Form No. 6. The FERC has stated that it will incorporate the effects of this change when it commences its next five-year review of the oil pipeline index in 2020, for rates that will take effect on July 1, 2021. The FERC has not yet commenced this proceeding and we are unable predict the outcome at this time.

Changes in the FERC's methodologies for approving rates could adversely affect us. 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 the Texas Intrastate System and 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, along with 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 the 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.

In July 2018, the FERC issued a final rule to address the impact of the Tax Cuts and Jobs Act on cost-of-service rates for jurisdictional natural gas pipelines. The final rule primarily impacts interstate pipelines regulated under the NGA. With respect to intrastate pipelines regulated by the FERC under the NGPA, the rule requires an intrastate pipeline with rates on file with a state regulatory agency to file with the FERC a new rate election for its interstate rates if the state rates are reduced to reflect the reduced income tax rates adopted in the Tax Cuts and Jobs Act. As of the date of this report, we have not been required to refile the rates for our intrastate systems as a result of this rule.

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 manipulation of energy markets. 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 natural 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 $1.2 million per day per violation as of January 2018.

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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 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 climate change and the environmental effects of greenhouse gas emissions and their associated consequences on 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 a long-term 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.

In response to scientific studies suggesting that emissions of certain gases, commonly referred to as greenhouse gases, including gases associated with oil and natural 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, with the U.S. being 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.

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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 and pricing for products handled by our midstream network, 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 plants and related NGL marketing activities encounter competition primarily from independent processors, major integrated oil companies, and financial institutions with commodity trading platforms. 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 business are major integrated 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 export terminal operations compete with those operated by major oil and gas and chemical companies and other midstream service providers primarily in terms of loading and offloading throughput capacity and access to related pipeline and storage infrastructure.

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 intense competition for supplies of crude oil at the wellhead. Competition is based primarily on quality of customer service, competitive pricing and proximity to customers and market hubs.

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Natural Gas Pipelines & Services

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. 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, in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our petrochemical marketing activities encounter competition from major integrated oil companies and various petrochemical companies that have varying levels of financial and personnel resources and competition generally revolves around product 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. Also, substantial new construction of inland marine vessels could create an oversupply and intensify competition for our marine transportation business.

For a discussion of the general risks involving competition, see "We face competition from third parties in our midstream energy business" under Part I, Item 1A of this annual report.

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 those at our Mont Belvieu complex, 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.

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§ 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 complex is 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. 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.

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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 volatile in recent years. For example, crude oil prices (based on WTI as measured by the NYMEX) ranged from a high of $76.41 per barrel to a low of $26.21 per barrel in the three year period ending December 31, 2018. Likewise, natural gas prices (based on Henry Hub as measured by the NYMEX) ranged from a high of $4.84 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.

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For a discussion regarding our current commercial outlook for 2019, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Outlook for 2019" 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 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.

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

As of December 31, 2018, we had $23.75 billion in principal amount of consolidated senior long-term debt outstanding and $2.67 billion in principal amount of junior subordinated debt 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 for 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 7 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.

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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 expenditures for 2018 reflected $4.49 billion of cash payments for capital projects and other investments. Based on information currently available, we expect our total capital expenditures for 2019 to approximate $3.5 billion to $3.9 billion, which includes $350 million for sustaining capital projects. 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;

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§ 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.

<u>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.</u>

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.

<u>The inability to continue to access lands owned by third parties could adversely affect our operations and have a material adverse effect on our financial position, results of operations and cash flows.</u>

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.

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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.

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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 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 attack or other 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.

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.

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A cyber-attack on our information technology ("IT") systems could affect our business and assets, and have a material adverse effect on our financial position, results of operations and cash flows.

We rely on our IT systems to conduct our business, as well as systems of third-party vendors. These systems include information used to operate our assets, as well as cloud-based services. These systems are subject to possible security breaches and cyber-attacks.

Cyber-attacks are becoming more sophisticated, and U.S. government warnings have indicated that infrastructure assets, including pipelines, may be specifically targeted by certain groups. These attacks include, without limitation, malicious software, ransomware, attempts to gain unauthorized access to data, and other electronic security breaches. These attacks may be perpetrated by state-sponsored groups, "hacktivists", criminal organizations or private individuals (including employee malfeasance). These cybersecurity risks include cyber-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 do not carry insurance specifically for cybersecurity events; however, certain of our insurance policies may allow for coverage of associated damages resulting from such events. 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.

Failure of our critical IT systems could have an adverse impact on our business, financial condition, results of operations and cash flows, as well as our ability to pay cash distributions.

We rely on IT systems to operate our assets and manage our businesses. We depend on these systems to process, transmit and store electronic information, including financial records and personally identifiable information such as employee, customer, investor and payroll data, and to manage or support a variety of business processes, including our supply chain, pipeline and storage operations, gathering and processing operations, financial transactions, banking and numerous other processes and transactions. Some of these IT systems are proprietary and custom designed for our business, while others are based upon or reside on commercially available technologies.

Failures of these IT systems, whether due to power failures, a cybersecurity event or other reason, could result in a breach of critical operational or financial controls and lead to a disruption of our operations, commercial activities or financial processes. Such failures could adversely affect our results of operations, financial position or cash flow, as well as our ability to pay cash distributions in a timely manner. State and federal cybersecurity legislation could also impose new requirements, which could increase our cost of doing business.

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.

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See Part II, Item 7A of this annual report and 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 Mountains, 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 integrated 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, 2018, we had $26.15 billion in principal amount of consolidated fixed-rate debt outstanding, including current maturities thereof. Due to the short term nature of commercial paper notes, we view the interest rates charged in connection with these instruments as variable.

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The Board of Governors of the Federal Reserve System raised benchmark interest rates three times during 2017, four times during 2018, and has stated that it expects to raise rates again in 2019. 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 in pipeline 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, 2018, 2017 and 2016 were $122.0 million, $91.1 million and $103.7 million, respectively. Of these annual totals, we charged $71.8 million, $52.3 million and $55.8 million to operating costs and expenses during the years ended December 31, 2018, 2017 and 2016, 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 $126 million for 2019.

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, Items 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.

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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 developments 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, Items 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.

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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, Items 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.

In October 2016, the FERC sought comments regarding potential modifications to its policies for evaluating changes in oil pipeline indexed rates and the associated 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 (i) revenues that exceed the total cost-of-service by 15% for the two preceding years or (ii) the proposed increase in the rate index exceeds the percentage change in the pipeline's annual costs by 5%. 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.

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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.

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 comment period on the reproposed rules closed on February 28, 2017, and the proposal remains pending.

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 Chairman and Commissioners have also indicated an interest in reevaluating 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. In addition, the President has nominated a new Chairman for the CFTC. (The existing Chairman's term expires in April 2019, although he can stay on for a period of time if his successor has not been confirmed.) It is not clear what, if any, effect a change in leadership at the CFTC would have on consideration of any changes in the existing regulations.

Our standalone operating cash flow is derived primarily from cash distributions we receive from EPO.

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 unconsolidated affiliates, 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 unconsolidated affiliates 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

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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 unconsolidated affiliates 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.

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.

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;

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- 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.

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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 31.9% 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.

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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.

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

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.

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.

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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, which would cause 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.

From 2013 through 2017, several publicly traded partnerships merged into their corporate general partner sponsors. In 2018 and continuing into 2019, the combination of a number of additional factors, including the passage of the Tax Cuts and Jobs Act of 2017 (which lowered the federal corporate tax rate from 35% to 21% and generally provides for the expensing of certain capital expenditures and acquisitions), the FERC issuing its Revised Policy Statement on the Treatment of Income Taxes in March 2018, and, generally, continued lower demand and related liquidity for midstream energy companies (including those structured as publicly traded partnerships) led to additional publicly traded partnerships to either (i) merge into their corporate general partner sponsors, (ii) merge into their general partner structured as a partnership and then elect for the combined entity to be taxed as a corporation, or (iii) voluntarily elect to be taxed as a corporation. These conversions have materially reduced the number of publicly traded partnerships and the total market capitalization and the depth of capital available for the publicly traded partnership sector.

While we currently believe that our classification as a partnership for federal income tax purposes continues to provide a net benefit for our unitholders, should we continue to see (i) additional publicly traded partnerships elect to be taxed as corporations, which could result in a further decrease in the total market capitalization of the publicly traded partnership sector, (ii) lower demand for equity capital in the publicly traded partnership sector, (iii) the absence of a historic premium in the market valuation of publicly traded partnerships compared to midstream energy companies taxed as corporations (or if we see any discount in the valuation of our partnership compared to such companies), or (iv) a combination thereof that results in a material difference in our cost of capital or limits our access to capital, the board of directors of our general partner may determine it is in our unitholders' best interest to change our classification as a partnership for federal income tax purposes. Should the general partner recommend that we change our tax classification, such change would be subject to the approval of our common 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.

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In addition, the Tax Cuts and Jobs Act (the "Tax Act") enacted December 22, 2017, made 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 the Treasury Department and IRS continue to release regulations relating to and interpretive guidance of the legislation contained in the Tax Act. 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 would pay the taxes directly to the IRS. 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. Our general partner would cause us to pay the taxes (including any applicable penalties and interest) directly to the IRS. 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.

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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 such as depreciation. 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.

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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.

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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.

Energy Transfer Matter

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

In September 2011, ETP filed suit against us and a third party in connection with the cancelled project alleging, among other things, that we and ETP had formed a "partnership." The case was tried in the District Court of Dallas County, Texas, 298th Judicial District. While we firmly believe, and argued during our defense, that no agreement was ever executed forming a legal joint venture or partnership between the parties, the jury found that the actions of the two companies, nevertheless, constituted a legal partnership. As a result, the jury found that ETP was wrongfully excluded from a subsequent pipeline project involving a third party, and awarded ETP $319.4 million in actual damages on March 4, 2014. On July 29, 2014, the 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 $0.8 million, plus interest.

On August 31, 2017, ETP filed a motion for rehearing before the Dallas Court of Appeals, which was denied on September 13, 2017. On December 27, 2017, ETP filed its Petition for Review with the Supreme Court of Texas and we filed our Response to the Petition for Review on February 26, 2018. On June 8, 2018, the Supreme Court of Texas requested that the parties file briefs on the merits, and the parties have filed their respective submittals. As of December 31, 2018, we have not recorded a provision for this matter as management continues to believe that payment of damages by us in this case is not probable. We continue to monitor developments involving this matter.

PDH Litigation

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

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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 penalties by governmental authorities related to administrative or judicial proceedings involving environmental matters. 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. We do not expect such expenditures to be material to our consolidated financial statements.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

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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, 2019, there were 2,445 unitholders of record of our common units. For information regarding our quarterly cash distributions to partners, see Note 8 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Recent Issuance of Unregistered Securities

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

Other than as described above, there were no issuances of unregistered equity securities during 2018.

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

The following table summarizes our equity repurchase activity during the fourth quarter of 2018:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Programs	Maximum Number of Units That May Yet Be Purchased Under the Programs
Vesting of phantom unit awards:			--	--
October 2018	--	--	--	--
November 2018 (1)	11,161	$ 26.98	--	--
December 2018	--	--	--	--
Common Unit Buyback Program:				
October 2018	--	--	--	1,236,800
November 2018	--	--	--	1,236,800
December 2018 (2)	1,236,800	$ 24.92	1,236,800	--

(1) Of the 42,290 phantom unit awards that vested in November 2018 and converted to common units, 11,161 units were sold back to us by employees to cover related withholding tax requirements. We cancelled these treasury units

immediately upon acquisition.
(2) In December 1998, we announced a common unit buyback, or repurchase, program whereby we, together with certain affiliates, could repurchase up to 4,000,000 of our common units on the open market. We purchased the remaining authorized amount of 1,236,800 common units in December 2018. We cancelled these treasury units immediately upon acquisition.

In January 2019, we announced that the Board of Enterprise GP had approved a $2.0 billion multi-year unit buyback program, which provides the partnership with an additional method to return capital to investors. The program authorizes the partnership to repurchase its common units from time to time, including through open market purchases and negotiated transactions. The timing and pace of buy backs under the program will be determined by a number of factors including (i) our financial performance and flexibility, (ii) organic growth and acquisition opportunities with higher potential returns on investment, (iii) our unit price and implied distributable cash flow yield and (iv) maintaining targeted financial leverage with a debt-to-normalized EBITDA, or earnings before interest, taxes, depreciation and amortization, ratio in the 3.5 times area. No time limit has been set for completion of the buyback program, and the program may be suspended or discontinued at any time.

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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. As presented in the table, amounts are in millions (except per unit data).

	For the Year Ended December 31,				
	2018	2017	2016	2015	2014
Statement of operations data:					
Total revenues	$36,534.2	$29,241.5	$23,022.3	$27,027.9	$47,951.2
Cost of sales	26,789.8	21,487.0	15,710.9	19,612.9	40,464.1
Other costs and expenses	4,815.8	4,251.6	4,092.7	4,248.4	3,970.9
Operating income	5,408.6	3,928.9	3,580.7	3,540.2	3,775.7
Net income	4,238.5	2,855.6	2,553.0	2,558.4	2,833.5
Net income attributable to limited partners	4,172.4	2,799.3	2,513.1	2,521.2	2,787.4
Earnings per unit:					
Basic ($/unit)	1.91	1.30	1.20	1.28	1.51
Diluted ($/unit)	1.91	1.30	1.20	1.26	1.47
Cash distributions per unit with respect to year	1.7250	1.6825	1.6100	1.5300	1.4500

	At December 31,				
	2018	2017	2016	2015	2014
Balance sheet data:					
Property, plant and equipment, net	$38,737.6	$35,620.4	$33,292.5	$32,034.7	$29,881.6
Total assets	56,969.8	54,418.1	52,194.0	48,802.2	47,057.7
Long-term debt, including current maturities	26,178.2	24,568.7	23,697.7	22,540.8	21,220.5
Total liabilities	32,677.6	31,645.7	29,928.0	28,301.1	27,365.5
Total equity	24,292.2	22,772.4	22,266.0	20,501.1	19,692.2
Limited partner units outstanding (millions)	2,184.9	2,161.1	2,117.6	2,012.6	1,937.3

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.

Our property, plant and equipment amounts increased over the last five years primarily due to investments in growth capital projects. For information regarding our capital investment program, see "Capital Investments" included under Part II, Item 7 of this annual report.

Debt increased over the last five years primarily due to the funding of a portion of our capital investments using borrowings under bank credit agreements and the issuance of short- and long-term notes. For information regarding our debt, see Note 7 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 our at-the-market program, distribution reinvestment plan and employee unit purchase plan. Net proceeds generated from the sale of common units were used to fund a portion of our capital investments.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

For the Years Ended December 31, 2018, 2017 and 2016

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, who is also an advisory director of Enterprise GP. 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 the President and Chief Financial Officer 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 Financial Officer of EPCO. EPCO, together with its privately held affiliates, owned approximately 31.9% of our limited partner interests at December 31, 2018.

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, 2018 (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," " "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

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to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Overview of Business

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

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the U.S., Canada and the Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations currently include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and export and import terminals (including those used to export liquefied petroleum gases, or "LPG," and ethane); crude oil gathering, transportation, storage, and export and import terminals; petrochemical and refined products transportation, storage, export and import terminals, and related services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems. Our assets currently include approximately 49,200 miles of pipelines; 260 MMBbls of storage capacity for NGLs, crude oil, petrochemicals and refined products; and 14 Bcf of natural gas storage capacity.

The safe operation of our assets is a top priority. 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. For additional information, see "Environmental, Safety and Conservation" within the Regulatory Matters section of Part I, Items 1 and 2 of this annual report.

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.

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 and other matters. For a discussion of the principal effects of such laws and regulations on our business activities, see "Regulatory Matters" included under Part I, Items 1 and 2 of this annual report.

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Significant Recent Developments

Enterprise Begins Service on the Shin Oak NGL Pipeline

In April 2017, we announced plans to build the 658-mile Shin Oak NGL Pipeline to transport growing NGL production from the Permian Basin to our NGL fractionation and storage complex located at the Mont Belvieu hub. The Mont Belvieu area in Chambers County, Texas, with its significant energy-related infrastructure, is a key hub of the global NGL industry (the "Mont Belvieu hub"). In February 2019, the 24-inch diameter mainline segment of the Shin Oak NGL Pipeline from Orla, Texas to Mont Belvieu was placed into limited commercial service with an initial transportation capacity of 250 MBPD. Completion of the related 20-inch diameter Waha lateral is scheduled for the second quarter of 2019. Supported by long-term customer commitments, the Shin Oak NGL Pipeline will ultimately provide up to 550 MBPD of transportation capacity, which is expected to be available in the fourth quarter of 2019.

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

In conjunction with the long-term NGL supply agreement, we granted Apache an option to acquire up to a 33% equity interest in our subsidiary that owns the Shin Oak NGL Pipeline. In November 2018, Apache contributed this option to Altus Midstream Company, which is a majority-owned subsidiary of Apache. The option is exercisable within sixty days after certain completion milestones are met (as defined in the underlying agreements), which we expect to occur in the second quarter of 2019.

Enterprise Announces $2 Billion Unit Buyback Program; Provides 2019 Distribution Guidance

In January 2019, we announced that the Board of Enterprise GP had approved a $2.0 billion multi-year unit buyback program, which provides the partnership with an additional method to return capital to investors. The program authorizes the partnership to repurchase its common units from time to time, including through open market purchases and negotiated transactions. The timing and pace of buy backs under the program will be determined by a number of factors including (i) our financial performance and flexibility, (ii) organic growth and acquisition opportunities with higher potential returns on investment, (iii) our unit price and implied distributable cash flow yield and (iv) maintaining targeted financial leverage with a debt-to-normalized adjusted EBITDA, or earnings before interest, taxes, depreciation and amortization, ratio in the 3.5 times area. No time limit has been set for completion of the buyback program, and the program may be suspended or discontinued at any time.

Also, based on current expectations, management announced its plans to continue to recommend to the Board an increase of $0.0025 per unit per quarter to our cash distribution rate with respect to 2019. The anticipated rate of increase would result in distributions for 2019 (of $1.7650 per unit) being 2.3% higher than those paid for 2018 (of $1.7250 per unit). 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.

Service Begins on the Midland-to-ECHO 2 Pipeline System

The Midland-to-ECHO 2 Pipeline System, which began limited commercial service in February 2019, provides us with approximately 200 MBPD of incremental crude oil transportation capacity from the Permian Basin to markets in the Houston area. The pipeline is expected to enter full commercial service in April 2019. The pipeline originates at our Midland terminal and extends 440 miles to our Sealy terminal, with volumes arriving at Sealy transported to our

ECHO terminal using the Rancho II pipeline, which is a component of our South Texas Crude Oil Pipeline System.

We converted a portion of our Seminole NGL Pipeline system from NGL service to crude oil service to create the Midland-to-Sealy segment of this pipeline system. The conversion is supported by a 10.75-year transportation contract with firm demand fees. The conversion does not reduce our NGL transportation capacity since displaced NGLs are transported using our other NGL pipelines, including our Shin Oak NGL Pipeline. Furthermore, we have the ability to convert this pipeline back to NGL service should market and physical takeaway conditions warrant.

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Enterprise Increasing NGL Fractionation Capacity in Texas and Louisiana

The demand for NGL fractionation capacity continues to expand as producers in domestic shale plays like the Permian Basin, Eagle Ford and Denver-Julesburg ("DJ") Basin seek market access and end users require supply assurance. In light of this ongoing trend, we are constructing a new NGL fractionation facility in Chambers County, Texas adjacent to our existing Mont Belvieu NGL fractionation complex. The new facility will consist of two fractionation trains capable of processing a combined 300 MBPD of NGLs. The first of the two fractionation trains will have a nameplate capacity of 150 MBPD and is scheduled to be completed and begin service in the fourth quarter of 2019. The second of these fractionation trains will also have a nameplate capacity of 150 MBPD, and is scheduled to begin service in the first half of 2020.

In November 2018, we announced a project to optimize our Shoup NGL fractionator located in Nueces County, Texas by expanding and repurposing a portion of our South Texas pipelines. This project would entail the construction of approximately 21 miles of new pipeline along with the conversion of approximately 65 miles of existing natural gas pipelines to NGL service, which will allow us to supply Shoup with an additional 25 MBPD of NGL volumes. The expanded pipeline capacity is expected to be available in the third quarter of 2019.

We restarted our Tebone NGL fractionator located in Ascension Parish, Louisiana in February 2019. Tebone has a fractionation capacity of 30 MBPD and is connected by pipeline to each of our Louisiana natural gas processing plants, as well as our Mont Belvieu storage complex. The resumption of service at Tebone complements our operations at the Norco and Promix NGL fractionators and provides us with another processing option for NGLs delivered to the Mont Belvieu hub.

The construction of our new 300 MBPD NGL fractionation facility at our Mont Belvieu NGL fractionation complex, the optimization of our Shoup facility and restart of our Tebone fractionator highlights the flexibility of our integrated midstream network and provides a timely, efficient and cost-effective solution for accommodating growing production from domestic shale basins. Once these projects are fully complete, total NGL fractionation capacity across our network would increase to approximately 1.1 MMBPD in the Mont Belvieu area, and approximately 1.5 MMBPD company-wide.

Enterprise Begins Construction of Seventh Natural Gas Processing Plant in Delaware Basin;
Second Train at Orla Natural Gas Processing Plant Begins Service

In October 2018, we announced that construction of our Mentone cryogenic natural gas processing plant had commenced. The Mentone plant, which is located in Loving County, Texas, is expected to have the capacity to process 300 MMcf/d of natural gas and extract in excess of 40 MBPD of NGLs. The project is scheduled to be completed in the first quarter of 2020 and is supported by a long-term acreage dedication agreement. The Mentone plant further extends our presence in the growing Delaware Basin and provides access to our fully integrated midstream asset network serving domestic and international markets. To support development of the Mentone plant, we are constructing approximately 70 miles of gathering and residue pipelines and expanding compression capabilities. These projects will allow the Mentone plant to link to our NGL system, including the Shin Oak NGL Pipeline which entered limited commercial service in February 2019, as well as our Texas Intrastate System. We will own and operate the Mentone facility and related infrastructure.

The Mentone plant will complement our existing cryogenic natural gas processing plant located near Orla, Texas in Reeves County. In May 2018 and October 2018, we commenced operations of the first and second processing trains (Orla I and Orla II), respectively, at the facility. A third processing train (Orla III) is scheduled to be completed in the second quarter of 2019. We own and operate the Orla facility. In conjunction with the start-up of Orla I, we placed into service approximately 70 miles of natural gas pipelines that connect the Orla facility to our Texas Intrastate

System.   We also placed into service a 30-mile extension of our NGL system that provides producers at the Orla facility with NGL takeaway capacity and direct access to our integrated network of downstream NGL assets.

When the Mentone plant is completed and placed into service, we expect to have an aggregate 1.6 Bcf/d of natural gas processing capacity and 250 MBPD of NGL production from our processing plants in the Delaware Basin.

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CME Group Launches Physical West Texas Intermediate ("WTI") Houston Crude Oil Futures Contract

In September 2018, the CME Group, a leading derivatives marketplace, announced that suppliers, refiners and end users of U.S. crude oil have a new way to price and hedge WTI in Houston, Texas. Participants will have the flexibility to make or take delivery of WTI at our ECHO terminal, Enterprise Hydrocarbons Terminal ("EHT") or pipeline interconnect at Genoa Junction. The new futures contracts received regulatory approval in October 2018 and are listed with and subject to the rules of the New York Mercantile Exchange ("NYMEX"), beginning with the January 2019 contract month.

Enterprise Expanding LPG Capacity at Houston Ship Channel Terminal

In September 2018, we announced a project to increase LPG loading capacity at EHT by 175 MBPD, or approximately 5 MMBbls per month. The expansion will bring our total LPG export capacity at EHT to 720 MBPD, or approximately 21 MMBbls per month. Upon completion of this expansion project, EHT will have the capability to load up to six Very Large Gas Carrier ("VLGC") vessels simultaneously, while maintaining the option to switch between loading propane and butane. Once operational, the expansion will allow EHT to load a single VLGC in less than 24 hours, creating greater efficiencies and cost savings for our customers. The incremental loading capacity is expected to be available in the third quarter of 2019.

Enterprise to Develop Offshore Texas Crude Oil Export Terminal

In July 2018, management announced that we are in the planning stage to develop a crude oil export terminal located offshore along the Texas Gulf Coast. The terminal would be capable of fully loading Very Large Crude Carrier ("VLCC") marine tankers, which have capacities of approximately 2 MMBbls and provide the most efficient and cost-effective solution to export crude oil to the largest international markets in Asia and Europe. We started front-end engineering and design work for the terminal in 2018 and filed our application for regulatory permitting with the Maritime Administration ("MARAD") in January 2019. Based on initial designs, the project could include pipelines extending from onshore facilities to an offshore terminal loading crude oil for export at approximately 85,000 barrels per hour. A final investment decision for the project will be subject to receiving state and federal permits and customer demand.

Seaway Commences Loading Services for VLCC Tankers

In June 2018, we commenced the loading of VLCC tankers using a combination of our jointly owned Seaway marine terminal located in Texas City, Texas and lightering operations in the Gulf of Mexico. Approximately 1.1 MMBbls of crude oil were loaded onto the FPMC C Melody at the Texas City marine terminal and the remainder of the crude oil shipment was loaded on the VLCC in a lightering zone in the Gulf of Mexico. The FPMC C Melody, chartered by Vitol, Inc., was the first VLCC to be loaded at a Texas port. The Seaway marine terminal features two docks, a 45-foot draft, an overall length of 1,125 feet, a 200-foot beam (width) and the capacity to load crude oil at a rate of 35,000 barrels per hour.

Affiliate of Western Gas Acquires 20% Ownership Interest in Portion of Midland-to-ECHO 1 Pipeline System

In June 2018, an affiliate of Western Gas Partners, LP ("Western") acquired a noncontrolling 20% equity interest in our subsidiary, Whitethorn Pipeline Company LLC ("Whitethorn"), for $189.6 million in cash. Whitethorn owns the majority of our Midland-to-ECHO 1 Pipeline System, which originates at our Midland terminal and extends 418 miles to our Sealy terminal. Volumes arriving at Sealy are then transported to our ECHO terminal using our Rancho II pipeline. The Midland-to-ECHO 1 Pipeline System provides Permian Basin producers with the ability to transport multiple grades of crude oil, including WTI, Light WTI, West Texas Sour, and condensate, to Gulf Coast markets. As a result of operating enhancements and supplementary infrastructure, the pipeline's transportation capacity is expected to increase to 620 MBPD beginning in March 2019. We report the pipeline's transportation volumes on a net basis that reflects our 80% interest.

Upon closing of the transaction whereby Western acquired its 20% equity interest in Whitethorn, we credited Western for 20% of the pipeline's earnings since it was placed into service in November 2017. We paid Western $45.7 million in June 2018 to settle this obligation.

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Construction Begins on Ethylene Export Dock

In May 2018, we announced that construction of our ethylene export terminal located at Morgan's Point on the Houston Ship Channel had commenced. When completed, the terminal, which we will operate, is expected to have an export capacity of approximately 2.2 billion pounds of ethylene per year, with loading rates of 2.2 million pounds per hour, and feature on-site refrigerated storage for 66 million pounds of ethylene. The project, which is underwritten by long-term customer commitments, is expected to begin limited commercial service in the fourth quarter of 2019, with full operations expected in the fourth quarter of 2020 once certain refrigeration assets are complete. We own a 50% equity interest in Enterprise Navigator Ethylene Terminal LLC, which owns the export terminal.

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

In May 2018, we announced the formation of a 50/50 joint venture with Energy Transfer Partners, L.P. ("ETP") to resume full service on the Old Ocean natural gas pipeline owned by ETP. The 24-inch diameter Old Ocean Pipeline originates in Maypearl, Texas in Ellis County and extends south approximately 240 miles to Sweeny, Texas in Brazoria County. ETP serves as operator of the pipeline, which has a natural gas transportation capacity of 160 MMcf/d. Repairs were completed on the pipeline and it entered full service in January 2019. In addition, both parties expanded their jointly owned North Texas 36-inch diameter natural gas pipeline, which is a component of our Texas Intrastate System. The expansion project was completed in January 2019 and provides us with additional natural gas takeaway capacity of 150 MMcf/d from West Texas, including deliveries into the Old Ocean Pipeline. The resumption of full service on the Old Ocean Pipeline and expansion of the North Texas Pipeline provide producers with additional takeaway capacity to accommodate growing natural gas production from the Delaware and Midland Basins.

Expansions of our Front Range and Texas Express Pipelines

In May 2018, we conducted open commitment periods to determine shipper interest in expansions of the Front Range Pipeline ("Front Range") and Texas Express Pipeline ("Texas Express"). Given the positive responses we received from shippers, we are proceeding with the expansion projects. We own a 33.3% equity interest in Front Range and a 35% equity interest in Texas Express. We operate both pipelines.

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

Acquisition of Remaining 50% Ownership Interest in Delaware Processing

In March 2018, we acquired the remaining 50% member interest in our Delaware Basin Gas Processing LLC ("Delaware Processing") joint venture for $150.6 million in cash, net of $3.9 million of cash held by the former joint venture. Delaware Processing owns a cryogenic natural gas processing facility (our "Waha" gas plant) having a capacity of 150 MMcf/d. The Waha plant is located in Reeves County, Texas and entered service in August 2016. The acquired business serves growing production of NGL-rich natural gas from the Delaware Basin in West Texas and southern New Mexico. For information regarding this acquisition, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Enterprise to Expand Butane Isomerization Facility

In January 2018, we announced plans to expand our butane isomerization facility by up to 30 MBPD of incremental capacity. The expansion is supported by long-term agreements to provide butane isomerization, storage and related pipeline services. We currently expect this project to be completed during the fourth quarter of 2021.

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General Outlook for 2019

We provide midstream energy services to producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products. Our financial position, results of operations and cash flows are contingent on the supply of and demand for the energy commodities we handle across our integrated midstream energy asset network. The following information presents our views on key midstream energy supply and demand fundamentals as they impact our operations going into 2019.

Supply Side Observations

The upstream energy industry, including major oil companies, continues to shift resources to shale supply basins. We believe that U.S. shale resources provide attractive economic benefits to producers due to their low risk and short lead time production profiles. Domestic shale resources will continue to play a key role in both U.S. and global markets, further supporting that the U.S. is a major oil supplier on par with the Organization of Petroleum Exporting Countries ("OPEC") and Russia.

During most of 2018, international energy commodity markets were supported as demand for crude oil was strong due to expanding global economic activity, while crude oil supplies were viewed as balanced and maintained through a regime of prescriptive supply cuts by OPEC and Russia. As a result crude oil prices improved significantly: WTI averaged $50.86 per barrel in 2017 and rose to $76.41 by early October 2018. Meanwhile, U.S. oil production rose steadily during that period averaging 9.4 MMBPD in 2017 and reached a record 11.8 MMBPD by December 2018. Likewise, U.S. production of NGLs averaged 3.8 MMBPD in 2017 and increased to 4.7 MMBPD by November 2018, a new record as well. U.S. crude oil and NGL production was expected to average 10.9 MMBPD and 4.4 MBPD, respectively, in 2018.

However, beginning in October 2018, signs of weakness began emerging in global energy markets due to perceived overproduction of crude oil and NGLs in the U.S. The impact of trade wars between the U.S., China and other developed economies, along with potential signs of economic slowdown in many developing economies, started eroding confidence in global demand. Also, there was uncertainty regarding how U.S. sanctions on Iran would be administered and their effect on Iranian oil exports. As a result, WTI oil prices tumbled from the high of $76.41 per barrel in early October 2018 to end the year at $45.41 per barrel, a decline of 41%. WTI prices averaged $64.90 per barrel for all of 2018.

In response to the rapid decline in crude oil prices, OPEC and Russia agreed to cut their overall production by 1.2 MMBPD during the first half of 2019, with 800 MBPD shouldered by OPEC and the remainder by Russia and other non-OPEC countries. All in all, OPEC and Russia reduced their production in 2017, 2018 and into 2019 as they adjust to the new reality. The U.S. has now secured its place as a major global oil supplier with production levels that match, if not surpass, Russia and Saudi Arabia. As such, the new imperative for non-U.S. producers is the delicate balancing of U.S., OPEC (primarily Saudi Arabia) and Russian production, while attempting to maintain crude oil prices at a level that ensures production doesn't grow too fast, but not too low as to cause massive fiscal deficits in oil producing nations that could threaten their political stability.

With the growth in domestic shale resources, U.S. natural gas production has increased significantly over the past few years with production estimates of 89 Bcf/d at the end of 2018. As a result, natural gas prices have been suppressed in recent years as a result of strong domestic supplies exceeding demand, particularly for heating needs as recent average winter temperatures have been warmer. As measured by the New York Mercantile Exchange ("NYMEX") at Henry Hub, natural gas prices for 2018 ranged from a high of $4.84 per MMBtu to a low of $2.55 per MMBtu, while averaging $3.07 per MMBtu. We believe that natural gas prices for 2019 will continue in a similar range. Natural gas production should be sufficient to meet both domestic and export demand, regardless of periodic fluctuations in demand and prices attributable to weather events.

U.S. exploration and production companies have shown that they can grow shale production at crude oil prices approximating $50 per barrel and higher. Drilling technology continues to improve, which enables producers to drill and complete non-conventional wells more efficiently. These improvements include faster drilling techniques, longer horizontal well laterals, higher density fracture treatments, and increased proppant concentration. Given that crude oil prices in 2018 were supportive of production growth, rig counts in the U.S. increased 17% during the year to 1,083

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at December 31, 2018. However, not all regions have reacted equally to the recovery in rig counts, with the largest increases seen in the Permian Basin (22% increase in 2018) and Eagle Ford Shale (14% increase in 2018).

As more wells were drilled in 2018, most shale basins experienced a shortage of completion equipment and crews, which forced producers to defer completions and build their inventory of drilled but uncompleted wells ("DUCs"). Rig counts plateaued during the second half of 2018, whereas the DUC count increased by 17% during the same period. The DUC count reached approximately 8,600 in December 2018 as reported by the U.S. Energy Information Administration ("EIA"), a 31% increase over the comparable December 2017 amount. More specifically, the Permian basin saw its DUC count increase 77% during 2018 as infrastructure constraints persisted, especially during the third quarter of 2018. The overall increase in DUCs represents a significant potential volume that we believe could be brought into production starting in 2019. We believe that NGL production will benefit disproportionately as these wells are brought online as producers seek greater returns from pursuing rich natural gas at the expense of dry gas wells, and from associated natural gas and NGLs produced in connection with higher crude oil production.

We operate in a number of major supply basins, including the Permian, Eagle Ford Shale, Haynesville Shale and Rockies. The following information represents our outlook for each of these basins:

§ The Permian Basin in West Texas and southeastern New Mexico has experienced the largest increase in drilling activity in the country, with 486 active rigs in December 2018. The basin continues to have many advantages relative to other producing regions, including stacked pay zones, light sweet crude oil and significant infrastructure. Based on producer feedback and forecasts, we believe that there is significant 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. Historically, the Delaware Basin has been a relatively lightly drilled area due to a lack of conventional targets. However, with the introduction of horizontal drilling and identification of stacked targets of tight-rock and shales, drilling in the Delaware Basin has accelerated over the past five years. These drilling targets have proven to produce not only crude oil but condensate and NGLs, which present us a significant number of opportunities to provide midstream services to producers. We are actively working with producers to identify those midstream infrastructure projects that will best serve their needs and also complement our integrated asset network.

Two examples of our initiatives in the Delaware Basin are the Orla and Mentone natural gas processing plants. During 2018, we placed two processing trains (Orla I and II) into service at Orla with a third (Orla III) expected to be completed in the second quarter of 2019. 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. Our Mentone facility was announced in October 2018 and is scheduled to enter service during the first quarter of 2020. When the Mentone plant is completed and placed into service, we expect to have an aggregate 1.6 Bcf/d of natural gas processing capacity and 250 MBPD of NGL production from our processing plants in the Delaware Basin.

Our Midland-to-ECHO 1 Pipeline System, which became fully operational in the second quarter of 2018, provides Permian Basin producers with the ability to transport multiple grades of crude oil on a segregated basis to Gulf Coast and international markets, thus maintaining and assuring the quality and grade of the final product. As a result of operating enhancements and supplementary infrastructure, the transportation capacity of the Midland-to-ECHO 1 Pipeline System is expected to increase to 620 MBPD beginning in March 2019. In addition, we placed our Midland-to-ECHO 2 Pipeline System into limited commercial service in February 2019, with full service expected in April 2019. The Midland-to-ECHO 2 Pipeline System provides us with approximately 200 MBPD of incremental crude oil transportation capacity from the Permian Basin to markets in the Houston area.

We are also evaluating several other natural gas, NGL and crude oil projects in the Permian Basin.

§ Crude oil and natural gas production in the Eagle Ford Shale is increasing due to higher rig counts and improved drilling efficiencies. The number of drilling rigs in the Eagle Ford Shale increased to 81 active rigs in December 2018 compared to a low of 29 rigs during the downturn in 2016. According to the EIA Drilling Productivity Report, the most recent data (December 2018) for production in the Eagle Ford Region was 1.4 MMBPD of crude oil and 7.0 Bcf/d of natural gas.

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Production acreage continues to change ownership in the Eagle Ford Shale, with over 1.5 million acres changing hands in 2018 and we expect this trend to continue. We believe that additional rigs will be brought to the basin as a result of the ownership changes, which could result in higher volumes for our midstream network; however, until volumes for the basin exceed historical peak production, there will likely be excess capacity of midstream infrastructure available in the region. 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. We also believe that the Eagle Ford Shale offers producers some of the best returns on capital of any region in the country due to its proximity to major consumption and export markets along the U.S. Gulf Coast and that midstream companies like us, with deep integrated networks, will enjoy the greatest operating leverage as production increases.

§ Natural gas production in the Haynesville Shale is also increasing due to higher rig counts and improved drilling efficiencies. The number of drilling rigs in the basin has increased from a low of 11 rigs in 2016 to 52 rigs in December 2018. Like the Eagle Ford Shale, we have seen several significant changes in the ownership of producing properties over the past year, which has contributed to increased drilling activity in the region by the new owners. The historical peak for natural gas production in the Haynesville region occurred in 2011 and was over 10.5 Bcf/d. According to the December 2018 EIA Drilling Productivity Report, Haynesville Region natural gas production was 9.8 Bcf/d.

The U.S. Geological Survey estimated in its 2017 assessment that the Haynesville Shale and the 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. The Haynesville Shale benefits from its close proximity to Gulf Coast markets where substantial petrochemical and liquefied natural gas, or LNG, export projects are being constructed. At expected natural gas price levels, we estimate that natural gas production from the Haynesville Shale will continue to increase; however, until volumes for the basin exceed historical peak production, there will likely be excess capacity of midstream infrastructure available in the region.

§ With respect to oil and gas production in the Rocky Mountain region, rig counts have declined slightly in the Jonah and Pinedale fields and are flat in the Piceance and San Juan basins. Producers plan to continue horizontal drilling in the Jonah field; however, horizontal drilling in the Pinedale field has generally been put on hold pending further study. Drilling has continued steadily in the Piceance field, with operators permitting the horizontal Williams Fork locations. Additional resources exist in the Piceance field in the deeper Mancos play, but it is currently not being developed. There were several changes in the ownership of producing properties in the San Juan basin this past year that are expected to lead to a modest increase in drilling activity by the new owners.

The Rockies benefit from sufficient natural gas and NGL pipeline infrastructure, which helps the region compete with other North American regions where production takeaway capacity may be constrained. We believe that our Rocky Mountain assets will continue to benefit regional producers by giving them access to major downstream markets such as the U.S. Gulf Coast and export destinations.

With stable to higher energy commodity prices and continued improvements in drilling and completion technologies, we expect continued strong investments, including both drilling and well completion activities, by producers during 2019 in and around our assets in the Permian Basin, Eagle Ford Shale, Haynesville Shale and Rocky Mountain regions. Furthermore, we believe that our assets in these areas are very competitive in providing midstream services. We also believe that production basins, along with supporting midstream infrastructure such as our integrated network, located closest to prime markets on the U.S. Gulf Coast will continue to be preferred by producers due to more favorable economics as compared to other more distant areas (mostly due to lower transportation costs).

Demand Side Observations

Global economic growth continues to drive increasing demand for petroleum-based products. In December 2018, the International Energy Agency ("IEA") reported that global demand for crude oil and NGLs grew by a combined 1.3 MMBPD in 2018 and expects demand to grow by 1.4 MMBPD in 2019. The IEA anticipates that overall demand for crude oil and NGLs by the countries represented by the Organization for Economic Co-operation and Development ("OECD") would decline by approximately 0.7 MMBPD between 2019 and 2023, while non-OECD demand would increase by 5 MMBPD over the same period. The IEA expects that petrochemicals will account for approximately 40% of the increase in global demand for crude oil and NGLs over this period.

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The North American "shale revolution" has made the U.S. the global, low-cost supplier of NGLs. We expect this trend to continue into 2019 and beyond supported by, among other things, the ability of U.S. shale producers to improve productivity and reduce development costs, higher demand in developing economies for crude oil and related hydrocarbons, and regulatory changes favoring the use of clean-burning fuels and low-sulfur hydrocarbons such as those found in domestic shale oil basins. We continue to foresee a variety of long-term demand-side opportunities from these developments, including higher demand from a resurgent U.S. petrochemical industry and increased exports of hydrocarbons (e.g., ethane, LPG and crude oil) to growing international markets.

With respect to the domestic petrochemical industry, abundant supplies of shale-sourced ethane provides the U.S. with one of the cheapest feedstocks available for ethylene production. The American Chemistry Council estimates that over $200 billion is being invested in domestic chemical production, with most of those investments tied directly to producing ethylene from cost-advantaged U.S. ethane. We believe that domestic demand for ethane is expected to continue growing as several new world-scale ethylene plants begin operations in 2019 and on through the early 2020s. Furthermore, virtually every ethane-consuming chemical plant in the U.S. is in close proximity to our existing assets.

Of the new domestic chemical plants, four are currently operational and have a combined ethylene production capacity of 11.1 billion pounds per year and ethane consumption rate of approximately 310 MBPD. An additional five plants are expected to enter service in 2019, with a combined ethylene production capacity of 10.5 billion pounds per year and an ethane consumption rate of approximately 295 MBPD, and another four in the early 2020s. The plants expected to enter service in the early 2020s are expected to have a combined ethylene production capacity of 10.8 billion pounds per year and an ethane consumption rate of approximately 295 MBPD. We also anticipate demand growth for ethane as a feedstock resulting from modifications made to other existing domestic facilities (e.g., debottlenecking, furnace modifications, etc.). As a result of the expected growth in U.S. ethylene production capacity, we are constructing an ethylene export terminal located at Morgan's Point on the Houston Ship Channel. The project, which is underwritten by long-term customer commitments, is expected to begin limited commercial service in the fourth quarter of 2019, with full operations expected in the fourth quarter of 2020 once certain refrigeration assets are complete.

International demand for U.S. ethane is expected to remain robust in 2019, as ethane from domestic shale basins also offers the global petrochemical industry a low-cost feedstock option plus supply diversification. Our Morgan's Point Ethane Export Terminal, the largest of its kind in the world, enables us to meet this demand and has an aggregate loading rate (nameplate capacity) of approximately 10,000 barrels per hour of fully refrigerated ethane.

Ethane prices were volatile in 2018 primarily due to supply and demand imbalances attributable to infrastructure gaps (e.g., NGL pipeline and fractionation capacity constraints). We, along with others in the midstream industry, are actively working to resolve these constraints. Overall, the industry expects to place over 1.8 MMBPD of pipeline capacity and 1.7 MMBPD of fractionation capacity into service between 2019 through 2021. However, due to uncertainty regarding the exact start-up dates for several ethane-oriented petrochemical plants, additional volatility in ethane prices cannot be ruled out in 2019.

We believe that U.S. exports of LPG to Asia, particularly China and India, and markets in Northwest Europe and Central and South America will continue to be strong. Per the EIA, U.S. LPG exports increased 9% in 2018 to 1,147 MBPD, based on data available through November 2018, with volumes headed to Asian markets accounting for approximately 50% of this amount (substantially all of which originated from our marine terminals). Our outlook for LPG exports to Asia is supported by a number of factors including: (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. Due to our expectation of continued growth in LPG exports, we announced a project to increase LPG loading capacity at EHT by 175 MBPD, or approximately 5 MMBbls per month. The incremental LPG loading capacity at EHT is expected to be available in the third quarter of 2019.

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Finally, as crude oil production in the U.S. has increased, these new domestic barrels continue to supplant more of the U.S.'s crude oil imports, while the remainder is exported to international markets in Central and South America, Asia and Western Europe where the lighter U.S. crudes are used as feedstock in their refining facilities. We also expect U.S. refiners to continue to operate at high rates as a result of steady U.S. demand and growing exports of refined products. We believe that our marine terminals and related storage and pipeline infrastructure that handle crude oil and refined products are strategically located to meet the concurrent needs of export and import customers. We have significant export capabilities on the Houston Ship Channel at EHT and at Beaumont, Freeport and Texas City, Texas.

Selected Energy Commodity Price Data

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

	Natural Gas, $/MMBtu (1)	Ethane, $/gallon (2)	Propane, $/gallon (2)	Normal Butane, $/gallon (2)	Isobutane, $/gallon (2)	Natural Gasoline, $/gallon (2)	Polymer Grade Propylene, $/pound (3)	Refinery Grade Propylene, $/pound (3)
2016 Averages	$ 2.46	$ 0.20	$ 0.48	$ 0.65	$ 0.68	$ 0.94	$ 0.34	$ 0.21
2017 by quarter:								
1st Quarter	$ 3.32	$ 0.23	$ 0.71	$ 0.98	$ 0.94	$ 1.10	$ 0.47	