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, 2020

OR

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

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of Registrant as Specified in Its Charter)

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

1100 Louisiana Street, 10th Floor, Houston, Texas 77002
(Address of Principal Executive Offices, including Zip Code)
(713) 381-6500
(Registrant's Telephone Number, including Area Code)

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange On Which Registered
Common Units	**EPD**	**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 every Interactive Data File required to be submitted 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 such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

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 our common units held by non-affiliates at June 30, 2020 (the last business day of the registrant's most recently completed second fiscal quarter) was $26.96 billion based on a closing price on that date of $18.17 per common unit on the New York Stock Exchange Composite ticker tape. There were 2,181,599,142 common units outstanding at January 31, 2021.

ENTERPRISE PRODUCTS PARTNERS L.P.
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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report on Form 10-K for the year ended December 31, 2020 (our "annual report") contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "would," "will," "believe," "may," "scheduled," "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 (including any forward-looking statements/expectations of third parties referenced in this annual report) 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.

KEY REFERENCES USED IN THIS REPORT

Unless the context requires otherwise, references to "we," "us" or "our" within this annual report are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to the "Partnership" mean Enterprise Products Partners L.P. on a standalone basis.

References to "EPO" mean Enterprise Products Operating LLC, which is an indirect wholly owned subsidiary of the Partnership, and its consolidated subsidiaries, through which the Partnership conducts its business. We are managed by our 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) W. Randall Fowler, who is also a director and the Co-Chief Executive Officer and Chief Financial Officer of Enterprise GP. Ms. Duncan Williams and Messrs. Bachmann and Fowler also currently serve as managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company, a privately held Texas corporation, and its privately held affiliates. 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) Mr. Bachmann, who serves as the President and Chief Executive Officer of EPCO; and (iii) Mr. Fowler, who serves as an Executive Vice President and the Chief Financial Officer of EPCO. Ms. Duncan Williams and Messrs. Bachmann and Fowler also currently serve as directors of EPCO.

We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates under the collective common control of the DD LLC Trustees and the EPCO Trustees. EPCO, together with its privately held affiliates, owned approximately 32.2% of the Partnership's common units outstanding and 30.2% of its Series A Cumulative Convertible Preferred Units ("preferred units") outstanding at December 31, 2020.

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

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." Our preferred units are not publicly traded. We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products. We are owned by our limited partners (preferred and common unitholders) from an economic perspective. Enterprise GP, which owns a non-economic general partner interest in us, manages our Partnership. We conduct substantially all of our business operations through EPO and its consolidated subsidiaries.

Our fully integrated, midstream energy asset network (or "value chain") 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 include:

- natural gas gathering, treating, processing, transportation and storage;
- NGL transportation, fractionation, storage, and marine terminals (including those used to export liquefied petroleum gases, or "LPG," and ethane);
- crude oil gathering, transportation, storage, and marine terminals;
- propylene production facilities (including propane dehydrogenation ("PDH") facilities), butane isomerization, octane enhancement, isobutane dehydrogenation ("iBDH") and high purity isobutylene ("HPIB") production facilities;
- petrochemical and refined products transportation, storage, and marine terminals (including those used to export ethylene and polymer grade propylene ("PGP"); and
- a marine transportation business that operates on key U.S. inland and intracoastal waterway systems.

Our business strategy seeks to leverage these operations to:

- capitalize on expected trends and opportunities in energy evolution and demand growth, including exports, for natural gas, NGLs, crude oil and petrochemical and refined products;
- maintain a diversified portfolio of midstream energy assets and expand this asset base through growth capital projects and accretive acquisitions of complementary midstream energy assets;
- enhance the stability of our cash flows by investing in pipelines and other fee-based businesses; and
- share capital costs and risks through 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.

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. See "*Current Outlook*" included under Part II, Item 7 of this annual report for management's views on key midstream energy supply and demand fundamentals in 2021.

Business Segments

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: NGL Pipelines & Services, Crude Oil Pipelines & Services, Natural Gas Pipelines & Services and Petrochemical & Refined Products Services.

Each of our business segments benefits from the supporting role of our marketing activities. The main purpose of our marketing activities is to support the utilization and expansion of assets across our midstream energy asset network by increasing the volumes handled by such assets, which results in additional fee-based earnings for each business segment. In performing these support roles, our marketing activities also seek to participate in supply and demand opportunities as a supplemental source of gross operating margin for us. 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 financial position, results of operations and cash flows are subject to certain risks. For information regarding such risks, see "Risk Factors" included under 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, including major customer information, see Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

NGL Pipelines & Services

This business segment includes our natural gas processing and related NGL marketing activities, NGL pipelines, NGL fractionation facilities, NGL and related product storage facilities, and NGL marine terminals.

<u>*Natural gas processing and related NGL marketing activities*</u>
At the core of our natural gas processing business are 21 processing facilities located in Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming.

In its raw form, natural gas produced at the wellhead (especially in association with crude oil production) contains varying amounts of NGLs such as ethane and propane. Natural gas streams containing NGLs and other impurities are usually not acceptable for transportation in downstream natural gas transmission pipelines or for commercial use as fuel; therefore, the unprocessed natural gas stream must be transported to a natural gas processing facility to remove the NGLs and other impurities. Once the natural gas is processed and the NGLs and impurities are removed, the residue natural gas meets downstream natural gas pipeline and commercial quality specifications.

In general, on an energy-equivalent basis, NGLs have greater economic value as feedstock for petrochemical and motor gasoline production than as components of a natural gas stream. Typical uses of NGLs 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.

The results of operations from natural gas processing 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.

Natural gas processing utilizes service contracts that are either fee-based, commodity-based or a combination of the two. Our commodity-based contracts include keepwhole, margin-band, percent-of-liquids, percent-of-proceeds and contracts featuring a combination of commodity and fee-based terms. To the extent we retain all or a portion of the extracted NGLs as consideration for our processing services, we refer to such volumes as our "equity NGL production."

If the operating costs of a natural gas processing facility are higher than the incremental value of the NGLs that would be extracted, then recovery levels of certain NGLs, primarily ethane, may be purposefully reduced. This scenario is typically referred to as "ethane rejection" and results in a reduction in NGL volumes available to us 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 by the marketing group. 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.

The following table presents selected information regarding our natural gas processing facilities at February 1, 2021:

Facility Name	Location	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	Wyoming	Green River	100.0%		1,100	1,100
Yoakum	Texas	Eagle Ford	100.0%		1,050	1,050
Pascagoula	Mississippi	Gulf of Mexico	75.0%	(2)	750	1,000
Orla	Texas	Delaware	100.0%		900	900
Chaco	New Mexico	San Juan	100.0%		600	600
Neptune	Louisiana	Gulf of Mexico	66.0%	(3)	430	650
Sea Robin	Louisiana	Gulf of Mexico	54.1%	(3)	352	650
Thompsonville	Texas	Eagle Ford	100.0%		330	330
Carthage (4)	Texas	Cotton Valley	100.0%		320	320
Mentone	Texas	Delaware	100.0%		300	300
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	Texas	Delaware	100.0%		150	150
Sonora	Texas	Strawn	100.0%		120	120
Venice	Louisiana	Gulf of Mexico	13.1%	(5)	98	750
Indian Springs	Texas	Wilcox-Woodbine	75.0%	(3)	90	120
Chaparral	New Mexico	Delaware	100.0%		45	45
Total					9,615	11,065

(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 own a 75% consolidated interest in the Pascagoula facility through our majority owned subsidiary, Pascagoula Gas Processing LLC.

(3) We proportionately consolidate our undivided interests in these operating assets.

(4) The Carthage processing complex consists of two natural gas processing plants: Panola and Bulldog.

(5) Our 13.1% 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 facilities were approximately 57.6%, 57.4% and 52.7% during the years ended December 31, 2020, 2019 and 2018, respectively.

Our NGL marketing activities utilize a fleet of approximately 880 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 135 tractor-trailer tank trucks that are used to transport LPG for us and on behalf of third parties. We own and operate the majority of these trucks and trailers.

NGL pipelines

Our NGL pipelines transport mixed NGLs from natural gas processing facilities, 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 governmental agencies, including the Federal Energy Regulatory Commission ("FERC"), or contractual arrangements. See "Regulatory Matters" within this Part I, Items 1 and 2 for information regarding governmental oversight of our liquids pipelines.

The following table presents selected information regarding our NGL pipelines at February 1, 2021:

Description of Asset	Location(s)	Ownership Interest	Pipeline Length (Miles)
Mid-America Pipeline System (1)	Midwest and Western U.S.	100.0%	7,977
South Texas NGL Pipeline System	Texas	100.0%	2,019
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%	877
Seminole NGL Pipeline (1)	Texas	100.0%	869
Shin Oak NGL Pipeline	Texas	67.0% (3)	664
Texas Express Pipeline (1)	Texas	35.0% (4)	594
Skelly-Belvieu Pipeline (1)	Texas, Oklahoma	50.0% (5)	572
Front Range Pipeline (1)	Colorado, Oklahoma, Texas	33.3% (6)	451
Houston Ship Channel Pipeline System	Texas	100.0%	304
Aegis Ethane Pipeline (1)	Texas, Louisiana	100.0%	299
Panola Pipeline (1)	Texas	55.0% (7)	253
Rio Grande Pipeline (1)	Texas	100.0%	249
Lou-Tex NGL Pipeline (1)	Texas, Louisiana	100.0%	206
Promix NGL Gathering System	Louisiana	50.0% (8)	194
Texas Express Gathering System	Texas	45.0% (9)	170
Tri-States NGL Pipeline (1)	Alabama, Mississippi, Louisiana	83.3% (10)	168
Others (eight systems) (2)	Various	Various (11)	459
Total			19,909

(1) Interstate transportation services provided by these liquids pipelines, in whole or part, are regulated by federal governmental agencies.

(2) 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.

(3) We own a 67% consolidated interest in the Shin Oak NGL Pipeline through our majority owned subsidiary, Breviloba, LLC.

(4) Our 35% ownership interest in the Texas Express Pipeline is held indirectly through our equity method investment in Texas Express Pipeline LLC.

(5) 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.

(6) Our 33.3% ownership interest in the Front Range Pipeline is held indirectly through our equity method investment in Front Range Pipeline LLC.

(7) We own a 55% consolidated interest in the Panola Pipeline through our majority owned subsidiary, Panola Pipeline Company, LLC.

(8) 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.

(9) Our 45% ownership interest in the Texas Express Gathering System is held indirectly through our equity method investment in Texas Express Gathering LLC.

(10) 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.

(11) We own a 74.7% consolidated interest in the 30-mile Wilprise pipeline through our majority owned subsidiary, Wilprise Pipeline Company, L.L.C. We proportionately consolidate our 50% undivided interest in a 45-mile segment of the Port Arthur pipelines. The remainder of these NGL pipelines are wholly owned.

The maximum number of barrels per day that our NGL pipelines can transport depends on the operating rates achieved at a given point in time between various segments of each system (e.g., demand levels at each 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 3,589 MBPD, 3,615 MBPD and 3,461 MBPD during the years ended December 31, 2020, 2019 and 2018, respectively.

We operate our NGL pipelines with the exception of the Texas Express Gathering System. The following information describes our principal NGL pipelines:

- The *Mid-America Pipeline System* is an NGL pipeline system consisting of the 3,119-mile Rocky Mountain pipeline, the 2,138-mile Conway North pipeline, the 632-mile Ethane-Propane ("EP") Mix pipeline, and the 2,088-mile Conway South pipeline. The Rocky Mountain pipeline transports mixed NGLs from production fields located in the Rocky Mountain Overthrust and San Juan Basin 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 facilities (owned by either us or third parties) to our NGL fractionators located in South Texas and at the Mont Belvieu hub in Chambers County, Texas. In addition, this system transports purity NGL products from our South Texas NGL fractionators to refineries and petrochemical plants located between Corpus Christi, Texas and Houston, Texas and within the Texas City-Houston area, as well as to interconnects with other NGL pipelines and to our Mont Belvieu storage complex. The South Texas NGL Pipeline System extends our ethane header system from the Mont Belvieu hub to Corpus Christi, Texas.

- The *Dixie Pipeline* transports propane and other NGLs from locations in southeast Texas, south Louisiana and Mississippi to markets in the southeastern U.S. 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 Appalachia-to-Texas Express, or *ATEX*, 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. Ethane originating at these fractionation facilities is sourced 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 facilities located in West Texas and New Mexico to the Mont Belvieu hub. 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 that transport 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 facilities, 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.

- The *Shin Oak NGL Pipeline* transports NGL production from Orla, Texas in the Permian Basin to our NGL fractionation and storage complex located at the Mont Belvieu hub.

- 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.

- 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.

- The *Front Range Pipeline* transports mixed NGLs from natural gas processing facilities 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.

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

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

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

NGL fractionation and related facilities

Our NGL fractionators separate mixed NGLs into purity NGL products for third-party customers and our NGL marketing activities. Mixed NGLs extracted by domestic natural gas processing facilities represent the largest source of volumes processed at our NGL fractionators. Based upon industry data, we believe that sufficient volumes of mixed NGLs, especially those originating from natural gas processing facilities located in West Texas, will be available for fractionation for the foreseeable future.

The results of operations from our NGL fractionation business are generally dependent upon the volume of mixed NGLs fractionated and either (i) the level of fractionation fees charged (under fee-based contracts) or (ii) the value of NGLs received (under percent-of-liquids arrangements). Under fee-based fractionation contracts, customers retain title to the NGLs that we process for them. Under percent-of-liquids fractionation contracts, we retain a portion of the purity NGLs we separate for customers and are exposed to commodity price risk through fluctuations in NGL prices. 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, 2021:

Description of Asset	Location	Ownership Interest	Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
NGL fractionation facilities:				
Mont Belvieu-area:				
Fracs I, II and III	Texas	75.0% (2)	189	245
Fracs IV, V, VI ,IX, X and XI	Texas	100.0%	645	645
Fracs VII and VIII	Texas	75.0% (3)	128	170
Total Mont Belvieu-area			962	1,060
Shoup and Armstrong	Texas	100.0%	93	93
Hobbs	Texas	100.0%	75	75
Norco	Louisiana	100.0%	75	75
Promix	Louisiana	50.0% (4)	73	145
Tebone	Louisiana	100.0%	30	30
Baton Rouge	Louisiana	32.2% (5)	19	60
Total			1,327	1,538

(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.
(4) Our 50% ownership interest in the Promix NGL fractionator is held indirectly through our equity method investment in K/D/S Promix, L.L.C.
(5) Our 32.2% ownership interest in the Baton Rouge fractionator is held indirectly through our equity method investment in Baton Rouge Fractionators LLC.

On a weighted-average basis, the overall utilization rates for our NGL fractionators (based on nameplate capacities) were 101.6%, 97.8% and 94.0% during the years ended December 31, 2020, 2019 and 2018, respectively.

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

- We own and operate NGL fractionators located in Mont Belvieu, Texas and surrounding areas of Chambers County, Texas. These fractionators process 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. Our Mont Belvieu-area NGL fractionators are connected 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.

  In 2020, we completed and placed into service two new NGL fractionators located in Chambers County, Texas that are adjacent to our other Mont Belvieu-area NGL fractionators: Frac X (March 2020) and Frac XI (September 2020). Completion of these two fractionators increased our total NGL fractionation capacity in the Mont Belvieu-area to approximately 1.1 MMBPD.

- The *Shoup and Armstrong* NGL fractionators in South Texas process mixed NGLs supplied by regional natural gas processing facilities. Purity NGL products from these 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.

- 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 facilities located in southern Louisiana and along the Mississippi and Alabama Gulf Coast, including our Pascagoula and Venice facilities.

We are currently constructing a 60 MBPD natural gasoline hydrotreater facility at our Mont Belvieu-area complex along with related storage and pipeline infrastructure. The new facility, which is designed to lower the sulfur content of natural gasoline, is scheduled to be completed and placed into service during the fourth quarter of 2021.

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 fees associated with each activity.

The following table presents selected information regarding our NGL and related product storage assets at February 1, 2021:

Description of Asset	**Location**	**Ownership Interest**	**Net Usable Storage Capacity (MMBbls)** (1)
Mont Belvieu storage complex	Texas	100.0%	129.8
Breaux Bridge, Anse La Butte and Sorrento (2)	Louisiana	100.0%	12.7
Almeda and Markham (3)	Texas	Leased	12.4
Petal (4)	Mississippi	100.0%	5.4
Hutchinson (5)	Kansas	100.0%	4.0
Others (6)	Various	Various	14.3
Total			178.6

(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 Louisiana Pipeline System.
(3) These storage facilities are used in connection with our South Texas NGL 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.

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 terminals (export and import) that handle NGLs. The results of operations from our NGL marine terminals, all of which are located on the Houston Ship Channel, are primarily dependent upon the level of volumes handled (loading and unloading) and the associated fees we charge for such services.

The following information describes our Houston Ship Channel terminals:

- The *Enterprise Hydrocarbons Terminal* ("EHT") 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, a barge dock and a lay berth 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 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, international demand for propane as a feedstock in ethylene production, and for power generation and heating purposes. The current estimated maximum loading capacity for LPG at EHT is approximately 835 MBPD. EHT has 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. EHT can load a single VLGC in less than 24 hours, creating greater efficiencies and cost savings for our customers. LPG loading volumes at EHT averaged 588 MBPD, 483 MBPD and 445 MBPD during the years ended December 31, 2020, 2019 and 2018, respectively.

  The primary customer of EHT is our NGL marketing group, which uses the terminal 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.

  EHT also includes an NGL import terminal. This import terminal can offload NGLs from tanker vessels at rates up to 8,000 barrels per hour depending on the product. Our NGL import volumes for the last three years were minimal.

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

- The *Morgan's Point Ethane Export Terminal*, located on the Houston Ship Channel, has a nameplate loading 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. Ethane volumes handled by the terminal are sourced from our Mont Belvieu-area NGL fractionators and storage complex. Ethane loading volumes at the terminal averaged 134 MBPD, 143 MBPD and 146 MBPD during the years ended December 31, 2020, 2019 and 2018, respectively.

Crude Oil Pipelines & Services

This business segment includes our crude oil pipelines, crude oil storage and marine terminals, and related 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 our crude oil pipelines are primarily dependent upon the volume of crude oil 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 governmental agencies, including the FERC, or contractual arrangements. See "Regulatory Matters" within this Part I, Items 1 and 2 for information regarding governmental oversight of our liquids pipelines.

The following table presents selected information regarding our crude oil pipelines and related operations at February 1, 2021:

Description of Asset	Location(s)	Our Ownership Interest	Operational Storage Capacity (MMBbls) (2)	Pipeline Length (Miles)
Midland-to-ECHO System:				
Midland-to-ECHO 1 pipeline	Texas	80.0% (3)	4.0	418
Midland-to-ECHO 2 pipeline	Texas	100.0%	–	444
Midland-to-ECHO 3 pipeline	Texas	29.0% (4)	–	521
Total Midland-to-ECHO System:			4.0	1,383
Seaway Pipeline (1)	Texas, Oklahoma	50.0% (5)	9.8	1,273
West Texas System (1)	Texas, New Mexico	100.0%	1.3	1,078
South Texas Crude Oil Pipeline System	Texas	100.0%	5.1	633
Basin Pipeline (1)	Texas, New Mexico, Oklahoma	13.0% (6)	6.0	618
EFS Midstream System	Texas	100.0%	0.3	525
Eagle Ford Crude Oil Pipeline System	Texas	50.0% (7)	4.5	390
Total			31.0	5,900

(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) The Midland-to-Sealy section of the Midland-to-ECHO 1 pipeline is owned by Whitethorn Pipeline Company LLC, in which we own an 80% consolidated interest.
(4) We proportionately consolidate our 29% undivided interest in the Midland-to-Webster pipeline, which we refer to as the Midland-to-ECHO 3 pipeline.
(5) Our 50% ownership interest in the Seaway Pipeline is held indirectly through our equity method investment in Seaway Crude Holdings LLC ("Seaway").
(6) We proportionately consolidate our 13% undivided interest in the Basin Pipeline.
(7) 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.

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 the 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 2,166 MBPD, 2,304 MBPD and 2,000 MBPD during the years ended December 31, 2020, 2019 and 2018, respectively.

We operate our crude oil pipelines with the exception of the Basin Pipeline, Eagle Ford Crude Oil Pipeline System and Midland-to-ECHO 3. The following information describes our principal crude oil pipelines:

- The *Midland-to-ECHO System* supports Permian Basin crude oil production by providing producers and other shippers with transportation solutions that are both cost-efficient and operationally flexible. After aggregating crude at our Midland terminal, the system has the capability to transport multiple grades of crude oil, including West Texas Intermediate ("WTI"), WTI light sweet crude oil ("West Texas Light"), West Texas Sour, and condensate, to our Enterprise Crude Houston ("ECHO") storage terminal (using batched shipments to safeguard crude quality) for further delivery to markets along the Gulf Coast. Using the ECHO terminal, shippers on the Midland-to-ECHO System have access to every refinery in Houston, Texas City, Beaumont and Port Arthur, Texas, as well as our crude oil export terminal facilities.

  The Midland-to-ECHO 1 pipeline 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, which is a component of our South Texas Crude Oil Pipeline System. The Midland-to-ECHO 1 pipeline has an approximate maximum transportation capacity of up to 620 MBPD, depending on certain operational variables.

The Midland-to-ECHO 2 pipeline originates at our Midland terminal and extends 444 miles to our Sealy terminal, with crude oil volumes arriving at Sealy transported to our ECHO terminal using the Rancho II pipeline. The Midland-to-ECHO 2 pipeline was created by converting the Midland-to-Sealy segment of one of our two Seminole NGL pipelines from NGL service to crude oil service. We retain the flexibility to convert this pipeline back to NGL service should future market conditions support the need for additional NGL transportation capacity out of the Permian Basin. The Midland-to-ECHO 2 pipeline has an approximate maximum transportation capacity of up to 225 MBPD, depending on certain operational variables.

In July 2019, we announced a third expansion of our Midland-to-ECHO System ("Midland-to-ECHO 3") comprised of a 36-inch pipeline extending from Midland, Texas to our ECHO terminal, and further from ECHO to a third-party terminal in Webster, Texas (collectively, the "Midland-to-Webster pipeline"). In October 2020, we announced that the Midland-to-ECHO segment of the Midland-to-Webster pipeline was placed into service. The ECHO-to-Webster segment was mechanically complete in December 2020. Once all facilities are placed into full commercial service, our maximum transportation capacity on the Midland-to-Webster pipeline is expected to approximate 450 MBPD.

In October 2019, we announced plans to construct a fourth pipeline (the "Midland-to-ECHO 4" pipeline) that would have connected our Midland terminal with our ECHO terminal by utilizing existing segments of our South Texas Crude Oil Pipeline System along with new construction. In September 2020, we cancelled this project in connection with the amendment of certain crude oil transportation agreements.

- The *Seaway Pipeline* connects the Cushing, Oklahoma crude oil hub with markets in southeast Texas. The Seaway Pipeline is comprised of the Longhaul System, the Freeport System and the Texas City System. The Cushing hub is an industry trading hub and price settlement point for 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 ECHO 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. We have used Seaway's Texas City terminal to partially load Very Large Crude Carrier ("VLCC") tankers, with the remaining volumes subsequently loaded on such vessels using 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 Loving County pipeline, is a key part of our strategic crude oil aggregation program designed to support Permian Basin producers. At Midland, shippers 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 along the Texas Gulf Coast.

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

- The *EFS Midstream System* serves producers in the Eagle Ford Shale, by providing condensate gathering and processing services as well as gathering, treating and compression services for associated natural gas. The EFS Midstream System includes 525 miles of gathering pipelines, 11 central gathering plants having a combined condensate storage capacity of 0.3 MMBbls, 201 MBPD of condensate stabilization capacity and 1.0 Bcf/d of associated natural gas treating capacity.

- 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 390 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 our Corpus Christi marine terminal.

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. Our system has access to an aggregate refining capacity of approximately 8 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 (loading and unloading) and the associated fees we charge for such services.

The following table presents selected information regarding our crude oil terminals at February 1, 2021:

Description of Asset	Location(s)	Ownership Interest	Number of Above-Ground Tanks in Service	Net Storage Capacity (MMBbls)
EHT (crude oil)	Texas	100.0%	81	23.4
ECHO (1)	Texas	100.0%	14	5.9
Beaumont Marine West	Texas	100.0%	12	4.2
Cushing	Oklahoma	100.0%	19	3.3
Midland (2)	Texas	100.0%	9	2.7
Corpus Christi	Texas	50.0% (3)	4	0.7
Total			139	40.2

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

(2) Number of tanks and storage capacity excludes three tanks that are used in the operation of our Midland-to-ECHO 1 pipeline.

(3) Our 50% ownership interest in the terminal is held indirectly through our equity method investment in Eagle Ford Terminals Corpus Christi LLC.

The following information describes our principal crude oil terminals, all of which we operate with the exception of the Corpus Christi terminal.

- Our *EHT* marine terminal located on the Houston Ship Channel includes export assets capable of loading up to 2.0 MMBPD, or 62 MMBbls per month, of crude oil. The crude oil terminal at EHT represents one of the largest such facilities on the Gulf Coast. As noted previously, EHT 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.

- The *Beaumont Marine West* terminal is located on the Neches River near Beaumont, Texas. This terminal includes three deep-water docks and one barge dock 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 pipelines.

- The *Corpus Christi* terminal, located in Corpus Christi, Texas, is capable of loading ocean-going vessels with either crude oil or condensate. The terminal includes one deep-water ship dock and serves Eagle Ford Shale and Permian Basin producers through a connection with our Eagle Ford Crude Oil Pipeline System.

Sea Port Oil Terminal. In July 2019, we announced the execution of long-term customer agreements supporting the development of our Sea Port Oil Terminal ("SPOT") in the Gulf of Mexico. As a result of these agreements, we announced our final investment decision with respect to SPOT, subject to obtaining the required approvals and licenses from the federal Maritime Administration, which is currently reviewing our SPOT application. We currently anticipate receiving approval for SPOT as early as the third quarter of 2021; however, we can give no assurance as to whether the project will ultimately be approved or the timing of such decision.

SPOT consists of proposed onshore and offshore facilities, including a fixed platform located approximately 30 nautical miles off the Brazoria County, Texas coast in approximately 115 feet of water. SPOT is designed to load a VLCC at rates of approximately 85,000 barrels per hour. We believe that SPOT's design meets or exceeds federal requirements for such facilities and, unlike existing and other proposed offshore terminals, is designed with a vapor control system to minimize emissions. SPOT would provide customers with an integrated export solution that leverages our extensive supply, storage and distribution network along the Gulf Coast, with access to approximately 6 MMBbls of crude oil supply and more than 300 MMBbls of storage based on our estimates.

In December 2019, we announced the execution of a letter of intent ("LOI") with an affiliate of Enbridge Inc. ("Enbridge") to jointly develop SPOT in the Gulf of Mexico. Under terms of the LOI, we agreed to negotiate an equity participation right agreement with Enbridge whereby, subject to SPOT receiving a deepwater port license, an affiliate of Enbridge could acquire a noncontrolling member interest in SPOT Terminal Services LLC, which owns SPOT.

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 310 tractor-trailer tank trucks, the majority of which we lease and operate, that are used to transport crude oil.

Natural Gas Pipelines & Services

This business segment includes our natural gas pipeline systems that provide for the gathering, treating and transportation of natural gas. This segment also includes our natural gas marketing activities.

Natural gas pipelines and related storage assets

Our natural gas gathering pipelines gather, treat and transport natural gas from production developments to regional natural gas plants for further processing. Our natural gas transmission pipelines transport natural gas from regional processing facilities to downstream electric generation plants, local gas distribution companies, industrial and municipal customers, storage facilities or other connecting 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 fees associated with each activity. Transportation 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 for information regarding governmental oversight of our natural gas pipelines.

The following table presents selected information regarding our natural gas pipelines and related infrastructure at February 1, 2021:

				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 (5)	6,893	7,345	–	12.9
Acadian Gas System (2)	Louisiana	100.0% (6)	1,307	3,100	–	1.3
Jonah Gathering System	Wyoming	100.0%	776	2,360	–	–
Piceance Basin Gathering System	Colorado	100.0%	191	1,800	–	–
San Juan Gathering System	New Mexico, Colorado	100.0%	6,117	1,750	420	–
Permian Basin Gathering System	Texas, New Mexico	100.0%	1,722	1,575	150	–
White River Hub (3)	Colorado	50.0% (7)	10	1,500	–	–
Haynesville Gathering System	Louisiana, Texas	100.0%	360	1,300	810	–
BTA Gathering System (4)	Texas	100.0% (8)	788	925	840	–
Indian Springs Gathering System (4)	Texas	80.0% (9)	145	160	–	–
Delmita Gathering System	Texas	100.0%	203	145	–	–
South Texas Gathering System	Texas	100.0%	517	143	220	–
Old Ocean Pipeline	Texas	50.0% (10)	240	80	–	–
Big Thicket Gathering System	Texas	100.0%	250	60	–	–
Central Treating Facility	Colorado	100.0%	–	–	200	–
Total			19,519	22,243	2,640	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) We proportionately consolidate our undivided interests, which range from 22% to 80%, in 1,471 miles of the Texas Intrastate System. 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.
(6) The Acadian Gas System includes a leased 1.3 Bcf underground salt dome natural gas storage cavern located at Napoleonville, Louisiana.
(7) Our 50% ownership interest in White River Hub is held indirectly through our equity method investment in White River Hub, LLC.
(8) This system includes approximately 52 miles of pipeline held under an operating lease.
(9) We proportionately consolidate our 80% undivided interest in the Indian Springs Gathering System.
(10) Our 50% ownership interest in the Old Ocean Pipeline is held indirectly through our equity method investment in Old Ocean Pipeline, LLC.

On a weighted-average basis, overall utilization rates for our natural gas pipelines were approximately 57.2%, 60.0% and 58.3% during the years ended December 31, 2020, 2019 and 2018, 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.

We operate our natural gas pipelines and storage facilities with the exception of the White River Hub, Old Ocean Pipeline and certain segments of the Texas Intrastate System. The following information describes our principal natural gas pipelines:

- The *Texas Intrastate System* is comprised of the 6,276-mile Enterprise Texas pipeline system and the 617-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 facilities 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.

- The *Acadian Gas System* transports, stores and markets natural gas in Louisiana. The Acadian Gas System is comprised of the 582-mile Cypress pipeline, 424-mile Acadian pipeline, 275-mile Haynesville Extension pipeline and 26-mile Enterprise Pelican pipeline. The Acadian Gas System links natural gas supplies from Louisiana (e.g., from the 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.

  In September 2019, we announced plans to expand and extend our Acadian Gas System in order to deliver natural gas production from the Haynesville Shale to the liquefied natural gas ("LNG") market in South Louisiana. The expansion project will include construction of an approximately 80-mile natural gas pipeline (the "Gillis Lateral") extending from near Cheneyville, Louisiana to third-party pipeline interconnects near Gillis, Louisiana, including multiple pipelines serving regional LNG export facilities. According to the FERC, the LNG market in South Louisiana and Southeast Texas includes facilities, including those under construction, featuring an aggregate 18 Bcf/d of export capacity. The Gillis Lateral is expected to have a transportation capacity of approximately 1 Bcf/d. In addition to construction of the Gillis Lateral, we plan to increase the transportation capacity of the Haynesville Extension from 1.8 Bcf/d to 2.1 Bcf/d by adding horsepower at our compressor station in Mansfield, Louisiana (the "Mansfield Project").

  The Mansfield Project and construction of the Gillis Lateral are supported by long-term customer contracts and are expected to begin service in the fourth quarter of 2021. Once the expansion project is completed, we expect that our Acadian Gas System will be able to deliver up to 2.1 Bcf/d of Haynesville Shale production into the LNG market, South Louisiana industrial complex and other pipeline interconnects that serve attractive southeastern U.S. markets.

- 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 facilities, 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 facility.

- 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 or to regional natural gas plants, including our Chaco facility, for further processing prior to being transported on interstate pipelines.

- The *Permian Basin Gathering System* is comprised of the 1,051-mile Carlsbad pipeline system, the 614-mile Waha pipeline system, the 34-mile Orla pipeline system and the 23-mile Mentone pipeline system. The Permian Basin Gathering System gathers natural gas from the Permian Basin for delivery to regional natural gas processing facilities, including our Chaparral, South Eddy, Waha, Mentone 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.

- The *Haynesville Gathering System* consists of the 217-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. This system includes our Fairplay Gathering System.

- 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 South Texas natural gas processing facilities.

- The *South Texas Gathering System* gathers natural gas from the Olmos and Wilcox formations for delivery to our South Texas natural gas processing facilities.

- 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. A third party serves as operator of the pipeline, which has a gross natural gas transportation capacity of 160 MMcf/d and entered full service in January 2019.

- 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 facilities 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.

Goodwill Impairment
In December 2020, we recognized a goodwill impairment charge of $296.3 million attributable to the Natural Gas Pipelines & Services business segment. For information regarding this charge, see Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Petrochemical & Refined Products Services

This business segment includes our:

- propylene production facilities, which include propylene fractionation units and a PDH facility, and related pipelines and marketing activities;
- butane isomerization complex and related deisobutanizer ("DIB") operations;
- octane enhancement, iBDH and HPIB production facilities;
- refined products pipelines, terminals and related marketing activities;
- an ethylene export terminal and related operations; and
- marine transportation business.

<u>*Propylene production facilities and related operations*</u>
Our propylene production facilities and related operations include propylene fractionation (or splitter) units, a PDH facility, propylene pipelines, propylene export assets and related petrochemical marketing activities.

Propylene production and related marketing activities. Propylene is a key feedstock used by the petrochemical industry. There are three grades of propylene: polymer grade propylene ("PGP"), with a minimum purity of 99.5%; chemical grade propylene ("CGP"), with a minimum purity of approximately 93-94%; and refinery grade propylene ("RGP"), with a purity of approximately 70%. Propylene fractionation units separate RGP, which is a mixture of propane and propylene, into either PGP or CGP. Our 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.

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 following table presents selected information regarding our propylene production facilities at February 1, 2021:

Description of Asset	Location	Our Ownership Interest	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)
Propylene fractionation facilities:				
Mont Belvieu (six units)	Texas	Various (1)	80	93
BRPC (one unit)	Louisiana	30.0% (2)	7	23
Total			87	116
PDH facility:				
PDH 1	Texas	100.0%	25	25

(1) We proportionately consolidate a 66.7% undivided interest in three of the propylene splitters, which have an aggregate 38 MBPD of total plant capacity. The remaining three propylene fractionation units are wholly owned.
(2) Our 30% ownership interest in the BRPC facility is held indirectly through our equity method investment in Baton Rouge Propylene Concentrator LLC ("BRPC").

We produce PGP at our Mont Belvieu facilities and CGP at our BRPC facility. On a weighted-average basis, the overall utilization rate of our propylene production facilities was approximately 79.4%, 86.7% and 86.7% during the years ended December 31, 2020, 2019 and 2018, respectively.

Global demand for propylene is increasing; however, the use of lighter crude oil feedstocks by U.S. refiners and increased use of ethane by steam crackers has reduced propylene production from these traditional sources. This has led to the development of more "on purpose" propylene production facilities such as our PDH 1 facility. This 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 upgrades approximately 35 MBPD of propane as feedstock. The PDH 1 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 construction of PDH 1 was underwritten by long-term, fee-based contracts that feature minimum volume commitments.

We have initiated legal proceedings involving the former general contractor for PDH 1. For a summary of this litigation, see Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

PDH 2. In September 2019, we announced the execution of long-term, fee-based contracts with affiliates of LyondellBasell Industries N.V. that support construction of our second PDH facility (referred to as "PDH 2"). In June 2020, we executed additional long-term PGP sales agreements with Marubeni Corporation in support of PDH 2. Like PDH 1, PDH 2 is expected to have the capacity to upgrade up to 35 MBPD of propane and produce up to 1.65 billion pounds per year of PGP. PDH 2 will be located in Chambers County, Texas at our Mont Belvieu complex and is scheduled to begin service in the second quarter of 2023. Once PDH 2 is placed into service and integrated with PDH 1 and our other propylene production facilities, we will have the capability to produce 11 billion pounds of propylene per year.

Propylene pipelines. The results of operations from our petrochemical pipelines are primarily dependent upon the volume of products transported and the associated fees we charge for such transportation services. The following table presents selected information regarding our propylene pipelines at February 1, 2021:

Description of Asset	Location(s)	Ownership Interest	Length (Miles)
Lou-Tex Propylene Pipeline	Texas, Louisiana	100.0%	267
North Dean Pipeline System	Texas	100.0%	189
Texas City RGP Gathering System	Texas	100.0%	157
Propylene Splitter PGP Distribution System	Texas	100.0%	92
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			830

(1) We proportionately consolidate our 50% 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 140 MBPD, 124 MBPD and 125 MBPD during the years ended December 31, 2020, 2019 and 2018, respectively.

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

Propylene export assets. Our EHT marine terminal located on the Houston Ship Channel includes export assets capable of loading up to 3,000 barrels per hour, or 72 MBPD, of semi-refrigerated propylene.

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. We also own and operate a 70-mile pipeline system used to transport high-purity isobutane from the Mont Belvieu hub to Port Neches, Texas.

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 ten 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 82.8%, 94.0% and 92.2% during the years ended December 31, 2020, 2019 and 2018, respectively.

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 15 MBPD, 24 MBPD and 25 MBPD during the years ended December 31, 2020, 2019 and 2018, 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 and iBDH facilities. 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 97.6%, 77.6% and 88.9% for the years ended December 31, 2020, 2019 and 2018, 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 December 2019, we completed construction and placed our iBDH unit into service. The facility, which is located at our Mont Belvieu complex and supported by long-term, fee-based contracts, is capable of processing approximately 25 MBPD of butane into nearly 1 billion pounds per year of isobutylene. Production from the iBDH plant enables us to optimize our MTBE and high purity isobutylene assets and meet growing market demand for isobutylene.

Steam crackers and refineries have historically 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 fuel additives.

Refined products services

Our refined products services business includes refined products pipelines, terminals and associated marketing activities.

Refined products pipelines. We own and operate the *TE Products Pipeline*, which is a 3,247-mile pipeline system comprised of 2,922 miles of regulated interstate pipelines and 325 miles of unregulated intrastate Texas pipelines. The system primarily transports refined products from the upper Texas Gulf Coast to Seymour, Indiana. From Seymour, segments of the TE Products Pipeline extend to Chicago, Illinois; Lima, Ohio; Selkirk, New York; and a location near Philadelphia, Pennsylvania. East of Seymour, Indiana, the TE Products Pipeline is primarily dedicated to NGL transportation service. The refined products transported by the TE Products Pipeline are produced by refineries and include motor gasoline and distillates.

The results of operations for this pipeline system are dependent upon the volume of products transported and the level of fees charged to shippers. The tariffs charged for such services are either contractual or regulated by governmental agencies, including the FERC. See "Regulatory Matters" within this Part I, Items 1 and 2 discussion for 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,		
	2020	2019	2018
Refined products transportation (MBPD)	419	407	456
Petrochemical transportation (MBPD)	156	126	148
NGL transportation (MBPD)	55	63	71

The TE Products Pipeline system includes five non-regulated refined products truck terminals and 19.6 MMBbls of aggregate storage capacity.

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 11.1 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 2.3 MMBbls of aggregate storage capacity through the use of 19 above-ground storage tanks.

The results of operations from 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.

Ethylene export terminal and related operations

In December 2020, our ethylene export terminal located at our Morgan's Point facility on the Houston Ship Channel entered full service with the commissioning of a refrigerated storage tank capable of handling 66 million pounds of ethylene. The ethylene export terminal, which had been in limited service since December 2019, features two docks and a nameplate capacity to load 1 million tons of ethylene per year. Ethylene is the primary feedstock for a wide variety of consumer products, including cell phones and computer parts, food packaging, apparel, textiles and personal protective equipment. We own a 50% member interest in Enterprise Navigator Ethylene Terminal LLC, which owns the export facility.

Our ethylene system serves as an open market storage and trading hub for the ethylene industry by incorporating storage capacity, connections to multiple ethylene pipelines, and high-volume export capabilities. In support of our ethylene business, our Mont Belvieu storage operations include a high-capacity underground ethylene storage well having a storage capacity of 600 million pounds of ethylene. The storage well is connected to our Morgan's Point ethylene export terminal and further to Bayport, Texas by a 27-mile pipeline.

In May 2019, we announced plans to further expand our ethylene pipeline and logistics system by constructing the Baymark ethylene pipeline in South Texas, which is a leading growth area for new ethylene crackers and related facilities. The Baymark pipeline will originate in Bayport and extend approximately 90 miles to Markham, Texas. The Baymark pipeline is supported by long-term customer commitments and is expected to begin service in mid-2021. We own a 70% consolidated interest in the Baymark pipeline through our majority owned subsidiary, Baymark Pipeline LLC. Customers using the Baymark pipeline will have pipeline access to our high-capacity ethylene storage well in Mont Belvieu and our export terminal at Morgan's Point.

<u>Marine transportation</u>
Our marine transportation business consists of 65 tow boats and 160 tank barges used to transport refined products, crude oil, asphalt, condensate, heavy fuel oil, LPG and other petroleum products on key U.S. inland and intracoastal waterway systems. The marine transportation industry uses tow boats as power sources and tank barges for freight capacity. Our marine transportation assets serve refinery and storage terminal customers along the Mississippi River, the intracoastal waterway between Texas and Florida, and the Tennessee-Tombigbee waterway system. We own and operate shipyard and repair facilities located in Houma and Morgan City, Louisiana and marine fleeting facilities located in Bourg, Louisiana and Channelview, Texas.

The results of operations from our marine transportation business are generally dependent upon the level of fees charged to transport petroleum products.

Our fleet of marine vessels operated at an average utilization rate of 86.1%, 94.0% and 93.5% during the years ended December 31, 2020, 2019 and 2018, 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.

In December 2020, we recognized an impairment charge of $256.7 million attributable to our marine transportation business. For information regarding this charge, see Note 4 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

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.

<u>Occupational Safety and Health</u>
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 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 Amendments 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 preventive 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 approximately $2.2 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 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. The SAFE PIPES Act also empowered PHMSA to address unsafe conditions or practices constituting 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. PHMSA published an interim rule in October 2016 and a final rule on October 1, 2019 to implement the agency's expanded authority to address imminent hazards to life, property, or the environment.

In response to the SAFE PIPES Act, PHMSA also issued an interim final rule in December 2016 and a final rule in January 2020 adopting federal safety regulations and reporting requirements for underground natural gas storage facilities. The final rule incorporates by reference American Petroleum Institute Recommended Practices 1170 and 1171, which outline safety standards for underground natural gas storage facilities and provide a minimum federal standard for inspection, enforcement and training.

In December 2020, the "Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020" ("PIPES Act") was signed into law. The PIPES Act extends the PHMSA's statutory mandate through 2023. It continues the legislative mandates that were established in the SAFE PIPES Act and creates new regulatory authorities for PHMSA or state agencies enforcing the federal pipeline safety regulations that include, among other things: (i) requiring regulations prescribing the applicability of pipeline safety requirements to idled natural gas transmission and hazardous liquids pipelines; (ii) updating existing large-scale LNG regulations; (iii) the creation of new leak detection and repair programs that impact certain gathering lines, new and existing transmission pipeline facilities, and new and existing gas distribution pipelines that have the dual purpose of meeting the need for gas pipeline safety and protecting the environment; (iv) necessitating updates to gas pipeline and hazardous liquid pipeline facility written inspection and maintenance plans; and (v) extensive new regulations governing gas distribution systems.

DOT regulations have also 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.

In October 2015, PHMSA issued proposed new or revised regulations under the Pipeline Safety Act and the SAFE PIPES Act that may impact our hazardous liquids pipelines. Several elements of the proposed rules were incorporated into a final rule issued by PHMSA in October 2019, significantly extending and expanding the reach of certain PHMSA integrity management requirements (for example, periodic assessments and expanded use of leak detection systems), regardless of the pipeline's proximity to an HCA. The final rule also requires all hazardous liquid pipelines in or affecting an HCA to be capable of accommodating in-line inspection tools within the next 20 years. In addition, the final rule extends annual, accident and safety-related conditional reporting requirements to gravity lines and certain gathering lines and also imposes inspection requirements on pipelines in areas affected by extreme weather events and natural disasters, such as hurricanes, landslides, floods, earthquakes or other similar events that are likely to damage infrastructure. This final rule became effective July 1, 2020.

In March 2016, 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 Moderate 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 ("MAOP") and requiring operators to report MAOP exceedances. PHMSA has since decided to split its 2016 proposed rule, which has become known as the "gas mega rule," into three separate rulemakings to facilitate completion. The first of these three rulemakings, relating to onshore gas transmission pipelines, was published as a final rule on October 1, 2019 and became effective on July 1, 2020. However, due to the COVID-19 pandemic, PHMSA announced a stay of enforcement of initial compliance deadlines to provide operators with additional time to incorporate the new procedures. The rule imposes numerous requirements on such pipelines, including MAOP reconfirmation, the periodic assessment of these pipelines in populated areas not designated as HCAs, the reporting of exceedances of MAOP, and the consideration of seismicity as a risk factor in integrity management. The PIPES Act requires PHMSA to issue the remaining rulemakings comprising the gas mega rule by the end of March 2021.

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.

The development and/or implementation of more stringent requirements pursuant to regulations implementing all of the requirements of the Pipeline Safety Act, the SAFE PIPES Act, or the PIPES Act, as well as any implementation of the PHMSA rules thereunder or reinterpretation of guidance by PHMSA or any state agencies with respect thereto, may result in us incurring significant and unanticipated expenditures to comply with such standards. Until any 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: 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.

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.

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.

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.

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%. On December 17, 2020, the FERC issued a final rule setting the index for the five-year period beginning July 1, 2021 at PPI plus 0.78%. 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 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. The D.C. Circuit upheld the Revised Policy and Order on Rehearing to a MLP pipeline on July 31, 2020 following court challenges initiated in September 2018.

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 crude oil and liquid pipelines with rates set using the indexing methodology, given that the current index will remain in effect through June 30, 2021. Following issuance of the Revised Policy, the FERC now requires crude oil and liquids pipelines owned by MLPs to remove the ITA from their cost-of-service reporting in FERC Form No. 6. In its final rule issued December 17, 2020, the FERC removed any effect of the change in ITA treatment in determining the index for rates that will take effect on July 1, 2021.

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 filing date of this annual 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. 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 approximately $1.3 million per day per violation as of January 2021. 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.

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 Discussion

There is considerable discussion over climate change and the environmental effects of greenhouse gas emissions and their associated consequences on global climate, oceans and ecosystems. Climate change 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 governmental, scientific and public concerns 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, contribute 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 from time to time has proposed legislative measures for imposing restrictions or requiring fees or carbon taxes for the emission of 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 emissions reduction, use of renewable energy, or use of replacement fuels with lower carbon content are under discussion and have and may continue to result in additional actions involving greenhouse gases.

These federal, regional and state measures generally apply to industrial sources (including facilities in the oil and gas sector) and suppliers and distributors of fuel, and could increase the operating and compliance costs of our pipelines, natural gas processing facilities, 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 facilities 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 and marine 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.

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 businesses*" 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.

- Residential demand for propane typically peaks during the winter months in connection with heating needs in rural areas. These seasonal trends can affect throughput volumes on our TE Products Pipeline, Dixie Pipeline and Mid-America Pipeline System and associated terminals.

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

- Extreme temperatures and ice during the winter months can negatively impact our gas processing plants as they may experience freeze offs. In addition, these conditions can negatively affect our trucking and inland marine operations on the upper Mississippi and Illinois rivers.

Workforce and Related Matters

Like many publicly-traded partnerships, we have no direct 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. The culture of our workforce is one of ownership, integrity, and opportunity. We recognize the hard work and contributions of individuals in our workforce who strive to further our goals. We promote an environment where our employees feel that working for us is more than just a job, it is a tight-knit community that looks out for one another. We respect employees' differences and believe everyone should be treated with fairness and respect. We value diverse ideas and perspectives, and are committed to promoting a safe and inclusive workforce.

As of February 1, 2021, there were approximately 7,130 EPCO personnel who spend all or a substantial portion of their time engaged in our business. From a diversity perspective, approximately 15% of these personnel were female and approximately 29% of these personnel were minorities. We believe that the diversity of our workforce compares favorably to the energy and chemical industries as a whole.

The health and safety of those working on our behalf is a top priority. We promote a culture in which all personnel share the same commitment to health and safety, and recognize the importance of mitigating risks. Acting upon our commitment to safety, we engage all levels of employees and management, our Board, our contractors, and various external entities and organizations. We strive to achieve a goal of zero incidents and injuries. We track our safety performance by monitoring our Total Recordable Incident Rate ("TRIR"), which is an OSHA measure that generally reflects the number of recordable incidents per 100 full-time workers during a one-year period. Our TRIR for 2020 was 0.48, which compares favorably to the average TRIR for the midstream industry over the last six years. We strive for year-to-year improvement in our safety performance.

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 unconsolidated 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.

ITEM 1A. RISK FACTORS.

Summary of Key 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

- The impacts from the COVID-19 pandemic and certain developments in the global oil markets have had, and may continue to have, material adverse consequences for general economic, financial and business conditions, and could materially and adversely affect our business, financial condition, results of operations and liquidity and those of our customers, suppliers and other counterparties.

- 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.

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

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

- 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.

- 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.

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

- 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.

- 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.

- 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.

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

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

- 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.

- Federal, state or local regulatory measures (including those related to climate, environmental, health, safety and pipeline integrity matters) 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.

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

Risks Relating to Our Partnership Structure

- 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.

- 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.

- 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.

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

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

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

- Unitholders may have a liability to repay distributions.

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

Tax Risks to Common Unitholders

- Our tax treatment depends on our status as a partnership for federal income tax purposes, which could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

- A successful IRS contest of the federal income tax positions we take and certain valuation methodologies we adopt in determining a unitholder's allocation of income, gain, loss and deductions, 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.

- 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 and our cash available for distribution to our unitholders might be substantially reduced.

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

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

- 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.

- 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.

Discussion of Key Risk Factors

The following discussion provides additional information regarding each of our key risk factors by category: Risks Relating to Our Business, Risks Relating to Our Partnership Structure and Tax Risks to Common Unitholders.

Risks Relating to Our Business

The impacts from the COVID-19 pandemic and certain developments in the global oil markets have had, and may continue to have, material adverse consequences for general economic, financial and business conditions, and could materially and adversely affect our business, financial condition, results of operations and liquidity and those of our customers, suppliers and other counterparties.

Changes in the supply of and demand for hydrocarbon products impacts both the volume of products that we sell and the level of services that we provide to customers, which in turn has a direct impact on our financial position, results of operations and cash flows. The continued global effects of the COVID-19 pandemic, which began in the first quarter of 2020 and include the consequences of international COVID-19 containment measures (e.g., quarantines, travel restrictions, temporary business closures and similar protective actions), reduced near-term demand for hydrocarbon products by record amounts and created a significant oversupply situation. Also, in the early stages of the pandemic, disputes between members of the Organization of the Petroleum Exporting Countries ("OPEC") and Russia (collectively, the "OPEC+" group) over crude oil production levels led to unprecedented volatility in global energy markets and a historic collapse in crude oil prices in April 2020. Although the OPEC+ group and other producers subsequently reached agreements to gradually reduce the oversupply of crude oil through production cuts, the downturn in the energy industry caused by lower demand and prices negatively impacted us, the producers we work with and our other customers to varying degrees.

Across the globe, many countries have eased their COVID-19 containment measures and central banks and governments have instituted fiscal measures in an effort to stimulate economic activity. As a result, hydrocarbon demand has started to recover; however, a continuation of this trend remains dependent on successful containment of the disease, the efficacy and distribution of approved vaccines on COVID-19 and its emerging variants, and proven therapeutics. Any prolonged period of economic slowdown or recession, or a protracted period of depressed demand or prices for crude oil or other products that we handle, could have significant adverse consequences on our financial condition and the financial condition of our customers, suppliers and other counterparties, and could diminish our liquidity and negatively affect the volumes of products handled by our pipelines and other facilities.

The ultimate impact of the pandemic on our financial condition, results of operations and cash flows depends largely on developments outside our control, including the duration of the outbreak, the related impact on overall economic activity, potential long-term impacts on demand for crude oil and other products and the willingness of the OPEC+ group to continue to reduce the oversupply of crude, all of which cannot be predicted with certainty.

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, public health emergencies, 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 a negative $37.63 per barrel in the three year period ended December 31, 2020. For the period January 1, 2021 through January 29, 2021, WTI prices ranged from a high of $53.57 per barrel to a low of $47.62 per barrel. 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 $1.48 per MMBtu over the three-year period ended December 31, 2020. Henry Hub natural gas prices ranged from a high of $2.76 per MMBtu to a low of $2.45 per MMBtu from January 1, 2021 through January 29, 2021.

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 crude 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; (viii) reduced demand for hydrocarbons attributable to public health emergencies and (ix) 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 a reduction in volumes available for transportation, fractionation, storage and marketing. 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 crude oil and natural gas prices, cost and availability of equipment and labor, regulatory changes, capital budget limitations, the lack of available capital or the probability of success in finding hydrocarbons. A decrease in exploration and development activities in the regions where our facilities and other energy logistic assets are located could result in a decrease in volumes handled by our assets, which could have a material adverse effect on our financial position, results of operations and cash flows.

For a discussion regarding our current outlook on industry fundamentals for 2021, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations – Current Outlook" 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 redeploy 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. A reduction in rates may result in lower returns on our investments and, as a result, lower the value of our assets.

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

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

As of December 31, 2020, we had $27.5 billion in principal amount of consolidated senior long-term debt outstanding and $2.65 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 investments;
- credit rating agencies may take a negative view of the energy sector or 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 investments, 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, 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 the energy sector or 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 investments or acquisitions, or to refinance existing indebtedness. If we are unable to access the capital markets on favorable terms in the future, we might be forced to seek extensions for some of our short-term debt obligations or to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected levels.

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

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

We will require substantial new capital to finance the future development and acquisition of assets and businesses. For example, our capital investments for 2020 reflected $3.32 billion of cash payments for capital projects and other investments. Based on information currently available, we expect our total capital investments for 2021, net of contributions from joint venture partners, to approximate $2.1 billion, which includes growth capital projects of $1.6 billion and sustaining capital expenditures of $440 million. 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 investments 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 service.

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

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

- we may be unable to complete construction projects on schedule or at the budgeted cost due to the unavailability of required construction personnel or materials, accidents, weather conditions or an inability to obtain necessary permits;

- we will not receive any material increase in operating cash flows until the project is completed, even though we may have expended considerable funds during the construction phase, which may be prolonged;

- we may construct facilities to capture anticipated future production growth in a region in which such growth does not materialize;

- since we are not engaged in the exploration for and development of crude oil or natural gas reserves, we may not have access to third party estimates of reserves in an area prior to our constructing facilities in the area. As a result, we may construct facilities in an area where the reserves are materially lower than we anticipate;

- in those situations where we do rely on third party reserve estimates in making a decision to construct assets, these estimates may prove inaccurate;

- the completion or success of our construction project may depend on the completion of a third party construction project (e.g., a downstream crude oil refinery expansion or construction of a new petrochemical facility) that we do not control and that may be subject to numerous of its own potential risks, delays and complexities; and

- we may be unable to obtain rights-of-way to construct additional pipelines or the cost to do so may be uneconomical.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A natural disaster, catastrophe, terrorist 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; however, insurance will not cover all types of interruptions that might occur, will not cover amounts up to applicable deductibles and will not cover all risks associated with the nature and extent of our operations. As a result of market conditions, premiums and deductibles for certain types of insurance (e.g., general liability policies) can increase substantially, and in some instances, such 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.

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.

IT policies and procedures protect our critical systems. Our cybersecurity approach is strategically layered with people, technology and processes such as disaster recovery, incident response and business continuity. However, the risk of critical systems failing due to an unforeseen major disruption is not eliminated.

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 on us, which could increase our cost of doing business.

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 or small-scale companies. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments, net out agreements and guarantees. However, these procedures and policies do not fully eliminate customer credit risk.

The primary markets for our services are 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 and gas companies, independent oil and gas companies and other pipelines and wholesalers operating in these markets. 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.

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

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

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

See 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 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 and gas 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, 2020, we had $29.9 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.

The Board of Governors of the Federal Reserve System raised benchmark interest rates four times during 2018, and again in early 2019 before lowering rates three times by the end of 2019, and lowered rates twice during 2020. 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.

Amounts borrowed under our 364-Day and Multi-Year Revolving Credit Agreements may bear interest, at our election, based on a London Interbank Offered Rate ("LIBOR"). In addition, our junior subordinated notes and interest rate swap agreements may also reflect LIBOR-based terms. In July 2017, the Financial Conduct Authority in the United Kingdom, or U.K., announced a desire to phase out LIBOR as a benchmark by the end of June 2023. Financial industry working groups are developing replacement rates and methodologies to transition existing agreements that depend on LIBOR as a reference rate. We currently do not expect the transition from LIBOR to have a material impact on us.

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, 2020, 2019 and 2018 were $82.7 million, $110.6 million and $122.0 million, respectively. Of these annual totals, we charged $52.9 million, $56.4 million and $71.8 million to operating costs and expenses during the years ended December 31, 2020, 2019 and 2018, 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 $119 million for 2021.

For additional information regarding the pipeline safety regulations, the Pipeline Safety Act and the SAFE PIPES Act, see "Regulatory Matters – Environmental, Safety and Conservation – 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 CERCLA and analogous state laws and regulations, may impose strict, joint and several liability for costs required to clean-up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could have a material adverse effect on our financial position, results of operations and cash flows.

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

Climate Change. Responding to reports regarding climate change matters, the U.S. Congress from time to time has considered legislation to reduce emissions of greenhouse gases or implement carbon taxes. In addition, certain states, including states in which our facilities or operations are located, have, individually or in regional cooperation, taken or proposed measures to reduce emissions of greenhouse gases. 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 are under discussion and have and may continue to result in additional actions involving greenhouse gases.

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, 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. Substantially all of our producer customers employ hydraulic fracturing techniques (commonly referred to as "fracking") 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 such activities. 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 Permian, 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 products 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.

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 and terms and conditions of service 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 Bureau of Labor's PPI for finished goods. For the five-year period ending June 30, 2021, the index is measured by the year-over-year change in the PPI, plus 1.23%. On December 17, 2020, the FERC issued a final rule setting the index for the five-year period beginning July 1, 2021 at PPI plus 0.78%. 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. Adverse decisions by the FERC in approving our regulated rates could adversely affect our financial position, results of operations and cash flows.

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.

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 investments 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 re-proposed rules on position limits. At its open meeting on October 15, 2020, the CFTC approved three final rules, including one regarding position limits for derivatives, completing the CFTC's major rulemakings related to implementation of the Dodd-Frank Act. The Final Rule on position limits for derivatives was approved by a 3-2 vote, amending regulations of speculative position limits to conform with certain Dodd-Frank amendments to the Commodity Exchange Act. Among other things, the CFTC adopted new and amended federal spot month position limits for derivatives contracts associated with 25 physical commodities and their economically equivalent futures, options and swaps, and amended single-month and all-months-combined federal limits for most of the agricultural contracts currently subject to federal position limits. Under the Final Rule, federal non-spot month position limits were not extended to the sixteen new physical commodities.

Additionally, the CFTC adopted new and amended definitions for use throughout the position limits regulations, including a revised definition of "bona fide hedging transaction or position" that includes an expanded list of enumerated bona fide hedges and a new definition of "economically equivalent swaps." The CFTC also amended rules governing exchange-set position limit levels and related exchange exemptions; established a new streamlined process for non-enumerated bona fide hedging recognitions for purposes of federal position limits; and amended certain regulatory provisions that would eliminate Form 204 (and the corresponding parts of Form 304), while also enabling the CFTC to leverage and receive cash-market reporting submitted directly to the exchanges by market participants. The Final Rule was published in the Federal Register January 14, 2021 and will become effective March 15, 2021.

While we believe that the majority of our hedging transactions would meet one or more of the enumerated categories for bona fide hedges under the Dodd-Frank Act, the rules could have an adverse impact on our ability to hedge certain risks associated with our business and could potentially affect our profitability.

Over time, the Executive Branch, the U.S. Congress and the CFTC itself may express interest in amending some of the statutory and regulatory provisions impacting financial markets and institutions and in reevaluating some of the existing regulations and regulatory proposals. In addition, the make-up of the CFTC, and its Chairman, changes periodically, often year-to-year, since the term for one CFTC seat expires each year. Those personnel changes can also impact the regulatory agenda. It is not clear what, if any, changes in the law may gain sufficient support to be enacted or what, if any, changes in the existing regulations might move forward and be adopted, or how any such changes would impact our hedging activity.

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

On a standalone basis, the Partnership 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, NGLs and other products; (v) relationships among natural gas, crude oil, NGL and other product 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. Due to 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 investments we make; (vi) the amount and cost of capital we can raise compared to the amount of our capital investments 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;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Unitholders may have a 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.

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 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.

From 2013 through 2017, several publicly traded partnerships merged into their corporate general partner sponsors. In 2018 and continuing into 2020, the combination of a number of additional factors, including the passage of the Tax Cuts and Jobs Act (the "Tax Act") of 2017 (which lowered the federal corporate tax rate from 35% to 21% and generally provides for the expensing of certain capital investments 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. 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, including elimination of partnership tax treatment for certain publicly traded partnerships.

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.

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.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

Our ability to deduct interest paid or accrued on indebtedness properly allocable to a trade or business ("business interest") may be limited in certain circumstances. Should our ability to deduct business interest be limited, the amount of taxable income allocated to our unitholders in the taxable year in which the limitation is in effect may increase. However, in certain circumstances, a unitholder may be able to utilize a portion of a business interest deduction subject to this limitation in future taxable years. Prospective unitholders should consult their tax advisors regarding the impact of this business interest deduction limitation on an investment in our common units.

Tax-exempt entities 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. With respect to taxable years beginning after December 31, 2017, subject to the proposed aggregation rules for certain similarly situated businesses or activities issued by the Treasury Department, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor regarding the impact of these rules on an investment in our common units.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our common units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). Income allocated to our unitholders and any gain from the sale of our common units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a common unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that common unit.

Moreover, upon the sale, exchange or other disposition of a common unit by a non-U.S. unitholder, the transferee is generally required to withhold 10% of the amount realized on such sale, exchange or other disposition if any portion of the gain on such sale, exchange or other disposition would be treated as effectively connected with a U.S. trade or business. The U.S. Department of the Treasury and the IRS have recently issued final regulations providing guidance on the application of these rules for transfers of certain publicly traded partnership interests, including transfers of our common units. Under these regulations, the "amount realized" on a transfer of our common units will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and such broker will generally be responsible for the relevant withholding obligations. Distributions to non-U.S. unitholders may also be subject to additional withholding under these rules to the extent a portion of a distribution is attributable to an amount in excess of our cumulative net income that has not previously been distributed. The U.S. Department of the Treasury and the IRS have provided that these rules will generally not apply to transfers of our common units occurring before January 1, 2022. Non-U.S. unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

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

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

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

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

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

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

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

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

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

ITEM 1B. UNRESOLVED SEC STAFF COMMENTS.

None.

ITEM 3. LEGAL PROCEEDINGS.

We may be named as defendants in legal proceedings in connection with our normal business activities. 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 legal proceedings. We will vigorously defend our partnership in litigation matters.

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

On occasion, we are assessed monetary penalties by governmental authorities related to administrative or judicial proceedings involving environmental matters. In June 2019, we received a Notice of Violation from the U.S. Environmental Protection Agency in connection with regulatory requirements applicable to facilities that we operate in Baton Rouge, Louisiana. The eventual resolution of this matter may result in monetary sanctions in excess of $0.3 million; however, we do not expect such expenditures to be material to our consolidated financial statements.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units are listed on the NYSE under the ticker symbol EPD. As of January 31, 2021, there were approximately 2,130 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 Issuances of Unregistered Securities

On September 30, 2020, we issued and sold an aggregate of 50,000 Series A Cumulative Convertible Preferred Units in a private placement transaction. The stated value of each preferred unit is $1,000 per unit. The total offering price for the preferred units was $50.0 million, of which $32.5 million was received in cash with the remaining $17.5 million funded through the exchange of 1,120,588 of our common units owned by the purchasers. Cash proceeds from the preferred unit offering include $15.0 million received from a privately held affiliate of EPCO for the purchase of 15,000 preferred units.

Concurrently, we exchanged all of the 54,807,352 Partnership common units owned directly by OTA for 855,915 of the new preferred units having an equivalent value. The preferred units held by OTA, like the common units OTA held prior to the exchange, are accounted for as treasury units by the Partnership in consolidation.

Holders of the preferred units are entitled to receive cumulative quarterly distributions at a rate of 7.25% per annum. We may satisfy our obligation to pay distributions to the preferred unitholders through the issuance, in whole or in part, of additional preferred units (referred to as paid-in kind or "PIK" distributions), with the remainder in cash, subject to certain rights of a holder to elect all cash and other conditions as described in our partnership agreement.

In November 2020, the Partnership made its first quarterly distribution to preferred unitholders, including PIK distributions of an aggregate of 8,067 restricted preferred units consisting of 7,929 preferred units to OTA (which are accounted for as treasury units in consolidation) and 138 preferred units to the privately held EPCO affiliate referenced above.

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

The issuances of the preferred units as PIK distributions during the three months ended December 31, 2020 were undertaken in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof.

Other than as described above, there were no sales of unregistered equity securities during the three months ended December 31, 2020.

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 2020:

Period	Total Number of Units Purchased		Average Price Paid per Unit	Total Number Of Units Purchased as Part of 2019 Buyback Program	Remaining Dollar Amount of Units That May Be Purchased Under the 2019 Buyback Program ($ thousands)
2019 Buyback Program: (1)					
October 2020	–	$	–	–	$1,745,312
November 2020	–	$	–	–	$1,745,312
December 2020	636,071	$	19.66	636,071	$1,732,808
Vesting of phantom unit awards:					
November 2020 (2)	20,759	$	16.63	n/a	n/a

(1) In January 2019, we announced the 2019 Buyback Program, which authorized the repurchase of up to $2 billion of our common units. Common units repurchased under this program during 2020 were cancelled immediately upon acquisition.

(2) Of the 83,609 phantom unit awards that vested in November 2020 and converted to common units, 20,759 units were sold back to us by employees to cover related withholding tax requirements. These repurchases are not part of any announced program. We cancelled these units immediately upon acquisition.

ITEM 6. SELECTED FINANCIAL DATA.

We voluntarily adopted the amended disclosure requirements under final SEC rules in Release No. 34-90459 applicable to Item 301 of Regulation S-K and Item 6 of Form 10-K on December 31, 2020. As a result, the five-year summary financial information formerly disclosed under Item 6 of Form 10-K is no longer applicable.

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

For the Years Ended December 31, 2020, 2019 and 2018

The following discussion and analysis of our financial condition, results of operations and related information for the years ended December 31, 2020 and 2019, including applicable year-to-year comparisons, 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.").

Discussion and analysis of matters pertaining to the year ended December 31, 2018 and year-to-year comparisons between the years ended December 31, 2019 and 2018 are not included in this Form 10-K, but can be found under Part II, Item 7 of our annual report on Form 10-K for the year ended December 31, 2019 that was filed on February 28, 2020.

Key References Used in this Management's Discussion and Analysis

Unless the context requires otherwise, references to "we," "us" or "our" within this annual report are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to the "Partnership" mean Enterprise Products Partners L.P. on a standalone basis.

References to "EPO" mean Enterprise Products Operating LLC, which is an indirect wholly owned subsidiary of the Partnership, and its consolidated subsidiaries, through which the Partnership conducts its business. We are managed by our 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) W. Randall Fowler, who is also a director and the Co-Chief Executive Officer and Chief Financial Officer of Enterprise GP. Ms. Duncan Williams and Messrs. Bachmann and Fowler also currently serve as managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company, a privately held Texas corporation, and its privately held affiliates. 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) Mr. Bachmann, who serves as the President and Chief Executive Officer of EPCO; and (iii) Mr. Fowler, who serves as an Executive Vice President and the Chief Financial Officer of EPCO. Ms. Duncan Williams and Messrs. Bachmann and Fowler also currently serve as directors of EPCO.

We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates under the collective common control of the DD LLC Trustees and the EPCO Trustees. EPCO, together with its privately held affiliates, owned approximately 32.2% of the Partnership's common units outstanding and 30.2% of its Series A Cumulative Convertible Preferred Units ("preferred units") outstanding at December 31, 2020.

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, 2020 (our "annual report") contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "would," "will," "believe," "may," "scheduled," "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 (including any forward-looking statements/expectations of third parties referenced in this annual report) are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct.

Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under Part I, Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Overview of Business

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." Our preferred units are not publicly traded. We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products. We are owned by our limited partners (preferred and common unitholders) from an economic perspective. Enterprise GP, which owns a non-economic general partner interest in us, manages our Partnership. We conduct substantially all of our business operations through EPO and its consolidated subsidiaries.

Our fully integrated, midstream energy asset network (or "value chain") 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 include:

- natural gas gathering, treating, processing, transportation and storage;
- NGL transportation, fractionation, storage, and marine terminals (including those used to export liquefied petroleum gases, or "LPG," and ethane);
- crude oil gathering, transportation, storage, and marine terminals;
- propylene production facilities (including propane dehydrogenation ("PDH") facilities), butane isomerization, octane enhancement, isobutane dehydrogenation ("iBDH") and high purity isobutylene ("HPIB") production facilities;
- petrochemical and refined products transportation, storage, and marine terminals (including those used to export ethylene and polymer grade propylene ("PGP"); and
- a marine transportation business that operates on key U.S. inland and intracoastal waterway systems.

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.

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.

Each of our business segments benefits from the supporting role of our marketing activities. The main purpose of our marketing activities is to support the utilization and expansion of assets across our midstream energy asset network by increasing the volumes handled by such assets, which results in additional fee-based earnings for each business segment. In performing these support roles, our marketing activities also seek to participate in supply and demand opportunities as a supplemental source of gross operating margin, a non-generally accepted accounting principle ("non-GAAP") financial measure, for us. 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 financial position, results of operations and cash flows are subject to certain risks. For information regarding such risks, see "Risk Factors" included under Part I, Item 1A of this annual report.

Current Outlook

As noted previously, this annual report on Form 10-K, including this update to our outlook on business conditions, contains forward-looking statements 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, which includes forecast information published by third parties. See "Cautionary Statement Regarding Forward-Looking Information" within this Part II, Item 7 and "Risk Factors" in Part I, Item 1A, for additional information. The following information presents our current views on key midstream energy supply and demand fundamentals. The third-party supply and demand forecasts cited in the following discussion, including our internal forecasts based on such information, remain subject to significant uncertainty because mitigation and reopening efforts related to COVID-19, emerging variants of COVID-19 and the introduction of approved vaccines and proven therapeutics continue to evolve.

All references to U.S. Energy Information Administration ("EIA") forecasts and expectations are derived from its February 2021 Short-Term Energy Outlook ("February 2021 STEO"), which was published on February 9, 2021.

Changes in the supply of and demand for hydrocarbon products impacts both the volume of products that we sell and the level of services that we provide to customers, which in turn has a direct impact on our financial position, results of operations and cash flows. The continued global effects of the COVID-19 pandemic, which began in the first quarter of 2020 and include the consequences of international COVID-19 containment measures (e.g., quarantines, travel restrictions, temporary business closures and similar protective actions), reduced near-term demand for hydrocarbon products by record amounts and created a significant oversupply situation. Also, in the early stages of the pandemic, disputes between members of the Organization of the Petroleum Exporting Countries ("OPEC") and Russia (collectively, the "OPEC+" group) over crude oil production levels led to unprecedented volatility in global energy markets and a historic collapse in crude oil prices in April 2020. Although the OPEC+ group and other producers subsequently reached agreements to gradually reduce the oversupply of crude oil through production cuts, the downturn in the energy industry caused by lower demand and prices negatively impacted us, the producers we work with and our other customers to varying degrees.

Supply Side Observations

Ongoing production cuts within the OPEC+ group, along with market-driven cuts in U.S., Brazilian and Canadian supplies, continue to provide much-needed support for international energy markets in coping with the ongoing weakness in hydrocarbon demand attributable to the pandemic. In April 2020, the OPEC+ group resolved their production dispute by agreeing to reduce their combined crude oil production by 9.7 MMBPD in May and June 2020, 9.6 MMBPD in July 2020, 7.7 MMBPD from August through December 2020, and 5.8 MMBPD from January 2021 to April 2022. In December 2020, the OPEC+ group revised their post-2020 production curtailments in light of current market dynamics and agreed to reduce their combined crude oil production by 7.2 MMBPD beginning in January 2021. The group will also hold monthly meetings to sign off on production adjustments for the following month, which would be no more than a 0.5 MMBPD increase. In addition, Saudi Arabia, the world's biggest oil exporter, said it would voluntarily reduce its production by 1.0 MMBPD in February and March in recognition of demand uncertainty related to the pandemic. The duration of market-driven production cuts by non-OPEC countries such as the U.S., Brazil and Canada will depend on supply and demand fundamentals. According to the February 2021 STEO, the EIA estimates that global production of petroleum and related liquids averaged 94.2 MMBPD in 2020, which represents a decline of 6.4 MMBPD when compared to 2019, and expects an average of 97.3 MMBPD in 2021 and 100.8 MMBPD in 2022.

As a result of the current business environment, most crude oil producers in North America have significantly reduced their drilling and completion of new wells compared to prior years. Baker Hughes reported that the total number of drilling rigs working in the continental U.S. (combined crude oil and natural gas rigs) declined from 805 at December 27, 2019 to 265 at June 26, 2020. The U.S. drilling rig count stood at 266 on October 2, 2020, but increased to 392 by February 5, 2021 due to strengthening energy fundamentals. In its February 2021 STEO, the EIA estimates that U.S. crude oil production averaged 11.3 MMBPD in 2020, which is down from an average of 12.3 MMBPD in 2019. According to the February 2021 STEO, the EIA expects U.S. crude oil production to decline to an average of 10.9 MMBPD in the second quarter of 2021 since near-term drilling and completion activity will not generate enough production to offset declines from existing wells. The EIA expects drilling activity to rise later in 2021, contributing to U.S. crude oil production returning to an average of 11.2 MMBPD in the fourth quarter of 2021 and 11.0 MBPD for 2021. The EIA forecasts U.S. crude oil production to average 11.5 MMBPD in 2022.

In its February 2021 STEO, the EIA estimates that U.S. natural gas production averaged 91.3 Bcf/d in 2020, which is down from an average of 93.1 Bcf/d in 2019. The EIA forecasts natural gas production to average 90.5 Bcf/d in 2021 and 91.0 Bcf/d in 2022. With the expected increase in U.S. crude oil production in late-2021, the EIA expects associated natural gas production from crude oil-directed wells to increase, especially in the Permian Basin region, and to average 90.5 Bcf/d in the fourth quarter of 2021.

Demand Side Observations

Across the globe, downstream demand for petroleum products such as gasoline and jet fuel has recovered from the lows of the second quarter of 2020, but remains depressed due to the effects of the pandemic and refiners have reduced their utilization rates in response. Many countries have eased their COVID-19 containment measures and central banks and governments have instituted fiscal measures in an effort to stimulate economic activity. As a result, hydrocarbon demand has started to recover; however, a continuation of this trend remains dependent on successful containment of the disease, the efficacy and distribution of approved vaccines on COVID-19 and its emerging variants, and proven therapeutics. In its February 2021 STEO, the EIA estimates that global demand for petroleum and related liquids averaged 92.3 MMBPD in 2020, and expects an average of 97.7 MMBPD in 2021 and 101.2 MMBPD in 2022. By contrast, the EIA estimates that global demand for petroleum and related liquids averaged 101.2 MMBPD in 2019 (pre-pandemic).

The decrease in hydrocarbon demand attributable to COVID-19 and the resulting oversupply situation caused a significant decrease in crude oil prices. Prior to the pandemic, crude oil prices for West Texas Intermediate ("WTI") at Cushing, Oklahoma (as reported by the NYMEX) closed at $61.06 per barrel on December 31, 2019. By March 31, 2020, WTI prices closed at $20.48 per barrel and, notwithstanding the announced OPEC+ production cuts, closed at a record low of a negative $37.63 per barrel on April 20, 2020. As demand began to recover starting in the second quarter of 2020, WTI prices rebounded from the April lows and closed at $39.27 per barrel on June 30, 2020. At September 30, 2020, WTI prices closed at $40.22 per barrel. At December 31, 2020, WTI prices closed at $48.52 per barrel as supply and demand fundamentals strengthened. Prices continue to increase as we begin 2021, averaging $52.10 per barrel in January 2021.

In its February 2021 STEO, the EIA estimates that U.S. consumption of natural gas averaged 83.3 Bcf/d in 2020, which reflects a 2.2% decrease from the 2019 average of 85.2 Bcf/d. The EIA expects U.S. consumption of natural gas to decrease to an average of 81.7 Bcf/d in 2021 and 81.0 Bcf/d in 2022 due to rising natural gas prices, which are expected to negatively impact demand from the electric power sector. Natural gas prices, as measured by the NYMEX at Henry Hub and reported in the February 2021 STEO, averaged $2.03 per MMBtu in 2020 compared to an average of $2.57 per MMBtu in 2019. The EIA forecasts Henry Hub spot prices to increase to an average $2.95 per MMBtu in 2021 due to rising space heating demand and liquefied natural gas exports amid the overall decrease in U.S. natural gas production expected for 2021. The EIA expects Henry Hub spot prices to average $3.27 per MMBtu in 2022.

Enterprise Outlook

We believe that crude oil prices will continue to increase. Our view considers the record retrenchment in drilling and completion activities worldwide, including by U.S. producers in 2020, along with steep decline curves in shale basins that result in lower near-term production through mid-2021, and the expected continuing recovery of global hydrocarbon demand following the pandemic. However, in the interim, we believe the midstream industry will be challenged in its supply-side businesses and that challenges and opportunities will be different for each producing basin.

Although the current industry and business outlooks remain challenging, we believe that our integrated, diversified and fee-based business model, will enable us to successfully traverse this difficult period. The Partnership and its consolidated operations remain in a strong position, with our financial strength and operational flexibility demonstrated by the following:

- At December 31, 2020, we had $6.06 billion of consolidated liquidity, which was comprised of $5.0 billion of available borrowing capacity under EPO's revolving credit facilities and $1.06 billion of unrestricted cash on hand. Our liquidity is supported by investment grade credit ratings on EPO's long-term senior unsecured debt of BBB+, Baa1 and BBB+ from Standard and Poors, Moody's and Fitch, respectively.

- EPO successfully issued $4.25 billion in principal amount of senior notes in 2020. Based on current conditions, we believe that we will have sufficient liquidity and/or access to debt capital markets to fund the remaining principal amount of senior notes maturing through 2021.

- In light of the current downturn in the domestic energy industry, we reevaluated our planned capital investments. Based on information currently available, we expect our total capital investments for 2021, net of contributions from joint venture partners, to approximate $2.1 billion, which reflects growth capital investments of $1.6 billion and sustaining capital expenditures of $440 million. In addition, we currently expect our growth capital investments in 2022 and 2023 for sanctioned projects to approximate $800 million and $400 million, respectively. These amounts do not include capital investments associated with our proposed deepwater offshore crude oil terminal (the Sea Port Oil Terminal or "SPOT"), which remains subject to governmental approvals. We currently anticipate receiving approval for SPOT as early as the third quarter of 2021; however, we can give no assurance as to whether the project will ultimately be approved or the timing of such decision.

- We continue to optimize our assets to provide incremental services to customers and to respond to market opportunities. As prices for certain NGLs, crude oil and refined products fell in 2020 due to collapsing demand for refined products as a result of the pandemic, our storage services provided valuable flexibility for our customers. In addition, our earnings from marketing activities in 2020 benefited from using uncontracted storage capacity to capture contango opportunities in NGLs, crude oil and refined products.

- Across all of our assets, we have contracted with a large number of quality customers in order to achieve customer diversification. In 2020, our top 200 largest customers represented 95.3% of consolidated revenues. Based on their respective year-end 2020 debt ratings, 81.4% of our top 200 customers were either investment grade rated or backed by letters of credit. Additionally, only 8.1% of our top 200 customer revenues were attributable to sub-investment grade or non-rated upstream producers.

In light of current events, we are closely monitoring the recoverability of our long-lived assets for potential impairment. We recognized a combined $890.6 million of non-cash asset impairment charges during the year ended December 31, 2020. If the adverse economic impacts of the pandemic persist for longer periods than currently expected, these developments could result in our recognition of additional non-cash impairment charges in the future.

Significant Recent Developments

Enterprise and Magellan to Develop Joint Houston Crude Oil Futures Contract

In January 2021, we and Magellan Midstream Partners, L.P ("Magellan") announced that our affiliates had entered into an agreement to jointly develop a futures contract for the physical delivery of crude oil in the Houston, Texas area in response to market interest for a Houston-based index with greater scale, flow assurance and price transparency. The quality specifications will be consistent with WTI crude oil originating from the Permian Basin with delivery capabilities at either our ECHO terminal in Houston or Magellan's East Houston terminal.

Ethylene Export Terminal Enters Full Service

In December 2020, our ethylene export terminal located at our Morgan's Point facility on the Houston Ship Channel entered full service with the commissioning of a refrigerated storage tank capable of handling 66 million pounds of ethylene. The ethylene export terminal, which had been in limited service since December 2019, features two docks and a nameplate capacity to load 1 million tons of ethylene per year. Ethylene is the primary feedstock for a wide variety of consumer products, including cell phones and computer parts, food packaging, apparel, textiles and personal protective equipment. We own a 50% member interest in Enterprise Navigator Ethylene Terminal LLC, which owns the export facility.

Our ethylene system serves as an open market storage and trading hub for the ethylene industry by incorporating storage capacity, connections to multiple ethylene pipelines, and high-volume export capabilities. In support of our ethylene business, our Mont Belvieu storage operations include a high-capacity underground ethylene storage well having a storage capacity of 600 million pounds of ethylene. The storage well is connected to our Morgan's Point ethylene export terminal and further to Bayport, Texas by a 27-mile pipeline.

Enterprise Joins The Alliance To End Plastic Waste

In December 2020, we became the first midstream company member of The Alliance to End Plastic Waste (the "Alliance"), which represents an international community of chief executive officers from across the plastic industry that are committed to addressing the global plastic waste challenge. Formed in 2019, the Alliance partners with a diverse and growing network of organizations, technical leaders, engineers and scientists, all dedicated to the goal of ending plastic waste. To achieve this goal, the Alliance focuses on four strategic areas – infrastructure, innovation, education and clean up – to unlock innovative solutions that will bring the world closer to the Alliance's ambition of diverting millions of tons of plastic waste in more than 100 at-risk cities across the globe by 2025.

Expansion of Midland-to-ECHO System Enters Service

In July 2019, we announced a third expansion of our Midland-to-ECHO System comprised of a 36-inch pipeline extending from Midland, Texas to our Enterprise Crude Houston ("ECHO") terminal, and further from ECHO to a third-party terminal in Webster, Texas (collectively, the "Midland-to-Webster pipeline"). We proportionately consolidate a 29% undivided interest in the Midland-to-Webster pipeline, which we refer to as the "Midland-to-ECHO 3" pipeline. In October 2020, we announced that the Midland-to-ECHO segment was placed into service. The ECHO-to-Webster segment was mechanically complete in December 2020. Once all facilities are placed into full commercial service, our maximum transportation capacity on the pipeline is expected to approximate 450 MBPD.

Amendments to Crude Oil Transportation Agreements; Cancellation of Midland-to-ECHO 4 Pipeline

In September 2020, we announced the amendment of certain crude oil transportation agreements and the related cancellation of the Midland-to-ECHO 4 pipeline. In general, the amendments provide for the reduction of near-term pipeline volume commitments in exchange for extending the term of the related transportation agreements and using existing pipeline infrastructure. Cancellation of the Midland-to-ECHO 4 pipeline reduced our growth capital investments by an aggregate $800 million over the years 2020 through 2022. As a result of the cancellation, we recorded an impairment charge of $42.2 million.

Execution of Long-Term PGP Sales Agreement in Support of PDH 2 Facility

In June 2020, we announced the execution of a long-term sales agreement with Marubeni Corporation to supply PGP from our second propane dehydrogenation plant ("PDH 2"), which is currently under construction at our Mont Belvieu complex. Marubeni Corporation is a major Japanese integrated trading and investment business conglomerate and the world's largest olefins trader. PGP is a primary petrochemical that has global demand growth as a feedstock to manufacture consumer, medical and industrial products that improve the daily lives and protect the health of people around the world.

PDH 2 is expected to have the capacity to upgrade 35 MBPD of propane into 1.65 billion pounds per year (equivalent to 25 MBPD) of PGP and begin service in the second quarter of 2023. Once PDH 2 is placed into service and integrated with PDH 1 and our other propylene production facilities, we will have the capability to produce 11 billion pounds of propylene per year.

Selected Energy Commodity Price Data

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

	Natural Gas, $/MMBtu	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound	Indicative Gas Processing Gross Spread $/gallon
	(1)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(4)
2019 by quarter:									
1st Quarter	$3.15	$0.30	$0.67	$0.82	$0.85	$1.16	$0.38	$0.24	$0.31
2nd Quarter	$2.64	$0.21	$0.55	$0.63	$0.65	$1.21	$0.37	$0.24	$0.25
3rd Quarter	$2.23	$0.17	$0.44	$0.51	$0.66	$1.06	$0.38	$0.23	$0.21
4th Quarter	$2.50	$0.19	$0.50	$0.68	$0.82	$1.20	$0.35	$0.21	$0.25
2019 Averages	$2.63	$0.22	$0.54	$0.66	$0.75	$1.16	$0.37	$0.23	$0.26
2020 by quarter:									
1st Quarter	$1.95	$0.14	$0.37	$0.57	$0.63	$0.93	$0.31	$0.18	$0.19
2nd Quarter	$1.71	$0.19	$0.41	$0.43	$0.44	$0.41	$0.26	$0.11	$0.17
3rd Quarter	$1.98	$0.22	$0.50	$0.58	$0.60	$0.80	$0.35	$0.17	$0.25
4th Quarter	$2.67	$0.21	$0.57	$0.76	$0.68	$0.92	$0.41	$0.24	$0.22
2020 Averages	$2.08	$0.19	$0.46	$0.59	$0.59	$0.77	$0.33	$0.18	$0.21

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

(2) NGL prices for ethane, propane, normal butane, isobutane and natural gasoline are based on Mont Belvieu Non-TET commercial index prices as reported by Oil Price Information Service.

(3) Polymer grade propylene prices represent average contract pricing for such product as reported by IHS Chemical, a division of IHS Inc. ("IHS Chemical"). Refinery grade propylene ("RGP") prices represent weighted-average spot prices for such product as reported by IHS Chemical.

(4) The "Indicative Gas Processing Gross Spread" represents our generic estimate of the gross economic benefit from extracting NGLs from natural gas production based on certain pricing assumptions. Specifically, it is the amount by which the assumed economic value of a composite gallon of NGLs at Mont Belvieu, Texas exceeds the value of the equivalent amount of energy in natural gas at Henry Hub, Louisiana. Our estimate of the indicative spread does not consider the operating costs incurred by a natural gas processing facility to extract the NGLs nor the transportation and fractionation costs to deliver the NGLs to market. In addition, the actual gas processing spread earned at each plant is determined by regional pricing and extraction dynamics.

The weighted-average indicative market price for NGLs was $0.38 per gallon in 2020 versus $0.47 per gallon for 2019.

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

	WTI Crude Oil, $/barrel (1)	Midland Crude Oil, $/barrel (2)	Houston Crude Oil $/barrel (2)	LLS Crude Oil, $/barrel (3)
2019 by quarter:				
1st Quarter	$54.90	$53.70	$61.19	$62.35
2nd Quarter	$59.81	$57.62	$66.47	$67.07
3rd Quarter	$56.45	$56.12	$59.75	$60.64
4th Quarter	$56.96	$57.80	$60.04	$60.76
2019 Averages	$57.03	$56.31	$61.86	$62.71
2020 by quarter:				
1st Quarter	$46.17	$45.51	$47.81	$48.15
2nd Quarter	$27.85	$28.22	$29.68	$30.12
3rd Quarter	$40.93	$41.05	$41.77	$42.47
4th Quarter	$42.66	$43.07	$43.63	$44.08
2020 Averages	$39.40	$39.46	$40.72	$41.21

(1) WTI prices are based on commercial index prices at Cushing, Oklahoma as measured by the NYMEX.
(2) Midland and Houston crude oil prices are based on commercial index prices as reported by Argus.
(3) Light Louisiana Sweet ("LLS") prices are based on commercial index prices as reported by Platts.

Fluctuations in our consolidated revenues and cost of sales amounts are explained in large part by changes in energy commodity prices. Energy commodity prices in 2020 fluctuated significantly due to the adverse economic effects of the COVID-19 pandemic and, with respect to crude oil prices in early 2020, the production dispute between Saudi Arabia and Russia. See "*Current Outlook*" within this Part II, Item 7 for information regarding these recent events.

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

We attempt to mitigate commodity price exposure through our hedging activities and the use of fee-based arrangements. See Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding our commodity hedging activities.

Income Statement Highlights

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

	For the Year Ended December 31, 2020	2019
Revenues	$ 27,199.7	$ 32,789.2
Costs and expenses:		
Operating costs and expenses:		
Cost of sales	16,723.2	22,065.8
Other operating costs and expenses	2,800.2	3,020.7
Depreciation, amortization and accretion expenses	1,961.5	1,848.3
Net gains attributable to asset sales	(4.4)	(5.7)
Asset impairment and related charges	890.6	132.7
Total operating costs and expenses	22,371.1	27,061.8
General and administrative costs	219.6	211.7
Total costs and expenses	22,590.7	27,273.5
Equity in income of unconsolidated affiliates	426.1	563.0
Operating income	5,035.1	6,078.7
Interest expense	(1,287.4)	(1,243.0)
Change in fair value of Liquidity Option	(2.3)	(119.6)
Other, net	16.0	16.6
Benefit from (provision for) income taxes	124.3	(45.6)
Net income	3,885.7	4,687.1
Net income attributable to noncontrolling interests	(110.1)	(95.8)
Net income attributable to preferred units	(0.9)	–
Net income attributable to common unitholders	$ 3,774.7	$ 4,591.3

Revenues

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

	For the Year Ended December 31, 2020	2019
NGL Pipelines & Services:		
Sales of NGLs and related products	$ 8,970.7	$ 10,934.3
Midstream services	2,206.5	2,536.4
Total	11,177.2	13,470.7
Crude Oil Pipelines & Services:		
Sales of crude oil	5,410.8	9,007.8
Midstream services	1,278.2	1,279.5
Total	6,689.0	10,287.3
Natural Gas Pipelines & Services:		
Sales of natural gas	1,530.5	2,075.4
Midstream services	1,022.6	1,094.0
Total	2,553.1	3,169.4
Petrochemical & Refined Products Services:		
Sales of petrochemicals and refined products	5,942.6	4,985.2
Midstream services	837.8	876.6
Total	6,780.4	5,861.8
Total consolidated revenues	$ 27,199.7	$ 32,789.2

Total revenues for 2020 decreased $5.59 billion when compared to 2019 primarily due to a net $5.15 billion decrease in marketing revenues. Revenues from the marketing of crude oil and natural gas decreased $4.14 billion year-to-year primarily due to lower average sales prices, which accounted for a $3.27 billion decrease, and lower sales volumes, which accounted for an additional $867.8 million decrease. Revenues from the marketing of NGLs decreased a net $1.96 billion year-to-year primarily due to lower average sales prices, which accounted for a $3.16 billion decrease, partially offset by the effects of higher sales volumes, which resulted in a $1.2 billion increase. Revenues from the marketing of petrochemicals and refined products increased a net $957.4 million year-to-year primarily due to higher sales volumes, which accounted for a $2.05 billion increase, partially offset by lower average sales prices, which resulted in a $1.1 billion decrease.

Revenues from midstream services for 2020 decreased $441.4 million when compared to 2019. Revenues from our natural gas processing facilities decreased $229.9 million year-to-year primarily due to lower market values for the equity NGLs we receive as non-cash consideration for processing services. Revenues from our Midland-to-ECHO 2 pipeline, which commenced limited service in February 2019 and full service in April 2019 and Midland-to-ECHO 3 pipeline, which commenced service in October 2020, increased a combined $49.6 million year-to-year. Revenues from our other pipeline assets decreased $179.8 million year-to-year primarily due to lower demand for crude oil, natural gas and refined products transportation services. Lastly, revenues from our Mont Belvieu-area NGL fractionators decreased $82.0 million year-to-year primarily due to lower fractionation fees.

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

Operating costs and expenses

Total operating costs and expenses for 2020 decreased $4.69 billion when compared to 2019 primarily due to lower cost of sales. The cost of sales associated with our marketing of crude oil and natural gas decreased a combined $3.83 billion year-to-year primarily due to lower average purchase prices, which accounted for a $3.19 billion decrease, and lower sales volumes, which accounted for an additional $634.4 million decrease. The cost of sales associated with our marketing of NGLs decreased a net $2.25 billion year-to-year primarily due to lower average purchase prices, which accounted for a $3.22 billion decrease, partially offset by higher sales volumes, which accounted for a $970.7 million increase. The cost of sales associated with our marketing of petrochemicals and refined products increased a net $736.9 million year-to-year primarily due to higher sales volumes, which accounted for a $1.81 billion increase, partially offset by lower average purchase prices, which accounted for a $1.07 billion decrease.

Other operating costs and expenses for 2020 decreased $220.5 million year-to-year primarily due to lower maintenance, chemicals and power-related expenses, which accounted for a $282.2 million decrease, partially offset by higher ad valorem taxes and employee compensation costs, which accounted for a $50.2 million increase. Depreciation, amortization and accretion expense increased $113.2 million year-to-year primarily due to assets placed into full or limited service since the first quarter of 2019 (e.g., the iBDH plant, Mentone and Orla gas processing facilities, Fracs X and XI and the Enterprise Navigator ethylene terminal).

Non-cash asset impairment charges increased $757.9 million year-to-year primarily due to the recognition in 2020 of the full impairment of goodwill associated with our Natural Gas Pipelines & Services business segment, which accounted for $296.3 million of expense, the partial impairment of our marine transportation business, which accounted for $256.7 million of expense, and the partial impairment of natural gas gathering and processing assets in South Texas, which accounted for an additional $125.7 million of expense. For information regarding these charges, see Notes 2, 4 and 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

General and administrative costs

General and administrative costs for 2020 increased $7.9 million when compared to 2019 primarily due to higher professional services and employee compensation costs.

Equity in income of unconsolidated affiliates

Equity income from our unconsolidated affiliates for 2020 decreased $136.9 million when compared to 2019 primarily due to decreased earnings from our investments in crude oil pipelines.

Operating income

Operating income for the year ended December 31, 2020 decreased $1.04 billion when compared to the year ended December 31, 2019 due to the previously described year-to-year changes in revenues, operating costs and expenses, general and administrative costs and equity in income of unconsolidated affiliates.

Interest expense

The following table presents the components of our consolidated interest expense for the years indicated (dollars in millions):

	For the Year Ended December 31,	
	2020	2019
Interest charged on debt principal outstanding	$ 1,330.6	$ 1,251.6
Impact of interest rate hedging program, including related amortization (1)	39.3	107.4
Interest costs capitalized in connection with construction projects (2)	(115.0)	(143.8)
Other (3)	32.5	27.8
Total	$ 1,287.4	$ 1,243.0

(1) Amount presented for the year ended December 31, 2019 reflects an unrealized, mark-to-market loss of $94.9 million recognized in September 2019 in connection with the exercise of swaptions. Due to declining interest rates, the counterparties to the swaptions exercised their right to put us into ten forward-starting swaps in September 2019 having an aggregate notional value of $1.0 billion. Since the swaptions were not designated as hedging instruments and were subject to mark-to-market accounting, we incurred an unrealized, mark-to-market loss at inception of the forward-starting swaps that is reflected as an increase in interest expense in 2019. The ten forward-starting swaps resulting from the swaption exercise were designated as hedging instruments and qualified for cash flow hedge accounting.

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

(3) Primarily reflects facility commitment fees charged in connection with our revolving credit facilities and amortization of debt issuance costs.

Interest charged on debt principal outstanding, which is a key driver of interest expense, increased a net $79.0 million year-to-year primarily due to increased debt principal amounts outstanding during 2020, which accounted for a $109.2 million increase, partially offset by the effect of lower overall interest rates during 2020, which accounted for a $30.2 million decrease. Our weighted-average debt principal balance for 2020 was $29.91 billion compared to $27.41 billion for 2019. In general, our debt principal balances have increased over time due to the partial debt financing of our capital investments. For information regarding our debt obligations, see Note 7 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Change in fair value of Liquidity Option

On February 25, 2020, we received notice from Marquard & Bahls AG ("M&B") of M&B's election to exercise its rights (the "Liquidity Option") under the Liquidity Option Agreement among the Partnership, OTA Holdings, Inc., a Delaware corporation previously named Oiltanking Holding Americas, Inc. ("OTA"), and M&B dated October 1, 2014 (the "Liquidity Option Agreement"). The Partnership settled its obligations under the Liquidity Option Agreement on March 5, 2020.

For the period in which the Liquidity Option was outstanding, we recognized non-cash expense in connection with accretion and changes in management estimates that affected the valuation of the Liquidity Option liability. Expense amounts attributable to changes in the fair value of the Liquidity Option were $2.3 million and $119.6 million during the years ended December 31, 2020 and 2019, respectively. The expense recognized for 2020 primarily reflects accretion expense for the period in which the Liquidity Option liability was outstanding before it was settled on March 5, 2020. The higher level of expense recognized in 2019 was primarily due to a decrease in the discount factor used in determining the present value of the liability.

For additional information regarding the exercise, see "Issuance of Common Units due to Settlement of Liquidity Option in March 2020" within the Liquidity and Capital Resources section of this Part II, Item 7. In addition, please refer to Note 8 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Income taxes

The following table presents the components of our consolidated benefit from (provision for) income taxes for the years indicated (dollars in millions):

	For the Year Ended December 31,	
	2020	**2019**
Deferred tax benefit attributable to OTA	$ 155.3	
Texas Margin Tax	(32.1)	$ (44.2)
Other	1.1	(1.4)
Benefit from (provision for) income taxes	$ 124.3	$ (45.6)

On March 5, 2020, the Partnership settled its obligations under the Liquidity Option Agreement and indirectly assumed the deferred tax liability of OTA, which reflects OTA's outside basis difference in the limited partner interests it received from the Partnership in October 2014. Upon settlement of the Liquidity Option, the Liquidity Option liability was effectively replaced by the deferred tax liability of OTA calculated in accordance with ASC 740, *Income Taxes*.

At March 5, 2020, the Liquidity Option liability amount was $511.9 million. Since the book value of the Liquidity Option liability exceeded OTA's estimated deferred tax liability of $439.7 million on that date, we recognized a non-cash benefit in earnings of $72.2 million, which is reflected in the "Benefit from (provision for) income tax" line on our Statement of Consolidated Operations for the year ended December 31, 2020. OTA recognized an additional net, non-cash deferred income tax benefit of $83.1 million primarily due to a decrease in the outside basis difference of its investment in the Partnership attributable to a decline in the market price of the Partnership's common units subsequent to March 5, 2020 through September 30, 2020. In total, our earnings for 2020 reflect $155.3 million of deferred income tax benefit attributable to OTA.

On September 30, 2020, OTA exchanged the Partnership common units it owned for non-publicly traded preferred units having a stated value of $1,000 per unit. As a result and beginning September 30, 2020, OTA's deferred tax liability no longer fluctuates due to market price changes in our common units. For information regarding the issuance of preferred units on September 30, 2020, including the OTA-related exchange, see "Liquidity and Capital Resources" within this Part II, Item 7.

For information regarding our income taxes, see Note 16 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Business Segment Highlights

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

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

	For the Year Ended December 31,	
	2020	2019
Gross operating margin by segment:		
NGL Pipelines & Services	$ 4,182.4	$ 4,069.8
Crude Oil Pipelines & Services	1,997.3	2,087.8
Natural Gas Pipelines & Services	926.6	1,062.6
Petrochemical & Refined Products Services	1,081.8	1,069.6
Total segment gross operating margin (1)	8,188.1	8,289.8
Net adjustment for shipper make-up rights	(85.7)	(24.1)
Total gross operating margin (non-GAAP)	$ 8,102.4	$ 8,265.7

(1) Within the context of this table, total segment gross operating margin represents a subtotal and corresponds to measures similarly titled within our business segment disclosures found under Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Total gross operating margin includes equity in the earnings of unconsolidated affiliates, but is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Total gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests. Our calculation of gross operating margin may or may not be comparable to similarly titled measures used by other companies. Segment gross operating margin for NGL Pipelines & Services and Crude Oil Pipelines & Services reflect adjustments for shipper make-up rights that are included in management's evaluation of segment results. However, these adjustments are excluded from non-GAAP total gross operating margin.

The GAAP financial measure most directly comparable to total gross operating margin is operating income. For a discussion of operating income and its components, see the previous section titled "Income Statement Highlights" within this Part II, Item 7. The following table presents a reconciliation of operating income to total gross operating margin for the years indicated (dollars in millions):

	For the Year Ended December 31,	
	2020	2019
Operating income	$ 5,035.1	$ 6,078.7
Adjustments to reconcile operating income to total gross operating margin (addition or subtraction indicated by sign):		
Depreciation, amortization and accretion expense in operating costs and expenses	1,961.5	1,848.3
Asset impairment and related charges in operating costs and expenses	890.6	132.7
Net gains attributable to asset sales in operating costs and expenses	(4.4)	(5.7)
General and administrative costs	219.6	211.7
Total gross operating margin (non-GAAP)	$ 8,102.4	$ 8,265.7

Each of our business segments benefits from the supporting role of our marketing activities. The main purpose of our marketing activities is to support the utilization and expansion of assets across our midstream energy asset network by increasing the volumes handled by such assets, which results in additional fee-based earnings for each business segment. In performing these support roles, our marketing activities also seek to participate in supply and demand opportunities as a supplemental source of gross operating margin for us. 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.

As a result of the COVID-19 pandemic and lower energy commodity prices, we experienced a reduction in volumes on a number of our assets (e.g., our crude oil pipelines and export docks and natural gas gathering systems) during the year ended December 31, 2020 due to reduced upstream drilling and production activity and lower downstream refinery activity and demand for transportation fuels. Furthermore, we may continue to experience throughput declines in the future on our gathering systems, long-haul liquids and natural gas pipelines and at our terminal and other facilities until the pandemic ends and economic activity is fully restored. For a general discussion of the impact of the pandemic on our partnership and industry, see "Current Outlook" within this Part II, Item 7.

NGL Pipelines & Services

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

	For the Year Ended December 31, 2020	2019
Segment gross operating margin:		
Natural gas processing and related NGL marketing activities	$ 997.5	$ 1,159.7
NGL pipelines, storage and terminals	2,524.1	2,402.2
NGL fractionation	660.8	507.9
Total	$ 4,182.4	$ 4,069.8
Selected volumetric data:		
NGL pipeline transportation volumes (MBPD)	3,589	3,615
NGL marine terminal volumes (MBPD)	722	626
NGL fractionation volumes (MBPD)	1,359	1,017
Equity NGL production volumes (MBPD) (1)	151	144
Fee-based natural gas processing volumes (MMcf/d) (2, 3)	4,285	4,738

(1) Represents the NGL volumes we earn and take title to in connection with our processing activities.
(2) Volumes reported correspond to the revenue streams earned by our natural gas processing plants.
(3) Fee-based natural gas processing volumes are measured at either the wellhead or plant inlet in MMcf/d.

Natural gas processing and related NGL marketing activities

Gross operating margin from natural gas processing and related NGL marketing activities for the year ended December 31, 2020 decreased $162.2 million when compared to the year ended December 31, 2019.

Gross operating margin from our natural gas processing facilities located in the Rocky Mountains (Meeker, Pioneer and Chaco plants) decreased a combined $94.2 million year-to-year primarily due to lower average processing margins (including the impact of hedging activities). On a combined basis, fee-based natural gas processing volumes at these plants decreased 319 MMcf/d year-to-year.

Gross operating margin from our South Texas natural gas processing facilities decreased $90.2 million year-to-year primarily due to lower average processing margins (including the impact of hedging activities), which accounted for a $51.2 million decrease, lower average processing fees, which accounted for a $23.9 million decrease, and lower processing volumes, which accounted for an additional $12.8 million decrease. On a combined basis, fee-based natural gas processing volumes at these plants decreased 156 MMcf/d and equity NGL production volumes increased 5 MBPD year-to-year.

Gross operating margin from our Louisiana and Mississippi natural gas processing facilities decreased a net $32.4 million year-to-year primarily due to lower average processing margins (including the impact of hedging activities), which accounted for a $33.4 million decrease, and lower processing volumes, which accounted for an additional $17.9 million decrease, partially offset by lower operating costs, which accounted for a $10.7 million increase, and higher average processing fees, which accounted for an additional $9.5 million increase. Net to our interest, fee-based natural gas processing and equity NGL production volumes at these plants decreased a combined 389 MMcf/d and 8 MBPD, respectively, year-to-year.

Gross operating margin from our Permian Basin natural gas processing facilities decreased a net $18.9 million year-to-year primarily due to lower average processing margins (including the impact of hedging activities), which accounted for a $42.5 million decrease, and lower average processing fees, which accounted for an additional $25.2 million decrease, partially offset by higher processing volumes, which accounted for a $54.8 million increase. On a combined basis, fee-based natural gas processing and equity NGL production volumes at our Permian Basin plants increased 363 MMcf/d and 8 MBPD, respectively, year-to-year, primarily due to additional processing capacity at our Orla facility that was placed into service in July 2019 and the start-up of our Mentone facility in December 2019.

Gross operating margin from our NGL marketing activities increased a net $71.5 million year-to-year primarily due to higher sales volumes, which accounted for a $248.9 million increase, partially offset by lower average sales margins (including the impact of hedging activities), which accounted for a $177.7 million decrease. The year-to-year increase in gross operating margin can be attributed to results from marketing strategies that seek to optimize our storage assets, which accounted for a $123.7 million increase, partially offset by lower earnings from strategies that seek to optimize our export, plant and transportation assets, which accounted for a combined $98.2 million decrease. In addition, gross operating margin from our NGL marketing activities attributable to non-cash, mark-to-market earnings increased $46.0 million year-to-year.

<u>*NGL pipelines, storage and terminals*</u>
Gross operating margin from our NGL pipelines, storage and terminal assets for the year ended December 31, 2020 increased $121.9 million when compared to the year ended December 31, 2019.

A number of our pipelines, including the Mid-America Pipeline System, Seminole NGL Pipeline, Chaparral NGL Pipeline, Shin Oak NGL Pipeline, Texas Express Pipeline and Front Range Pipeline, serve Permian Basin and/or Rocky Mountain producers. On a combined basis, gross operating margin from these pipelines increased a net $65.8 million year-to-year primarily due to higher average transportation fees, which accounted for a $64.9 million increase, and lower operating costs, which accounted for an additional $36.4 million increase, partially offset by lower transportation volumes of 101 MBPD (net to our interest), which accounted for a $25.9 million decrease.

Gross operating margin from LPG-related activities at EHT increased $62.7 million year-to-year primarily due to higher export volumes of 105 MBPD. The increase in export volumes is attributable to an LPG expansion project at EHT that was completed in the third quarter of 2019. Gross operating margin from our Houston Ship Channel Pipeline System increased $21.5 million year-to-year primarily due to an 86 MBPD increase in transportation volumes. Gross operating margin at our Morgan’s Point Ethane Export Terminal increased $8.6 million year-to-year primarily due to lower operating costs. Export volumes from our Morgan’s Point Ethane Export Terminal decreased 9 MBPD year-to-year.

Gross operating margin from our Aegis Pipeline increased a net $27.3 million year-to-year primarily due to a 107 MBPD increase in transportation volumes associated with contract commitments, which accounted for a $43.0 million increase, partially offset by higher operating costs, which accounted for a $9.5 million decrease.

Gross operating margin from our South Louisiana NGL Pipeline System and related storage facilities decreased a combined $22.6 million year-to-year primarily due to lower transportation volumes of 60 MBPD, which accounted for an $11.9 million decrease, and lower terminal revenues, which accounted for an additional $6.0 million decrease. Gross operating margin from our Lou-Tex NGL Pipeline decreased $8.4 million year-to-year primarily due to lower transportation volumes of 24 MBPD.

Gross operating margin from our Mont Belvieu storage facility decreased a net $16.6 million year-to-year primarily due to lower handling and throughput fee revenues, which accounted for a $45.6 million decrease, partially offset by higher storage fees, which accounted for a $32.1 million increase.

Gross operating margin from our South Texas NGL Pipeline System decreased $11.9 million year-to-year primarily due to lower pipeline capacity fee revenues earned from an affiliate pipeline. Transportation volumes on our South Texas NGL Pipeline System increased 15 MBPD year-to-year.

<u>*NGL fractionation*</u>
Gross operating margin from NGL fractionation during the year ended December 31, 2020 increased $152.9 million when compared to the year ended December 31 2019. Gross operating margin from our Mont Belvieu-area NGL fractionators increased $123.9 million primarily due to higher fractionation volumes, which increased 353 MBPD year-to-year (net to our interest) primarily due to the start-up of Frac X and Frac XI in March 2020 and September 2020, respectively. Gross operating margin from our Hobbs NGL fractionator increased $20.2 million year-to-year primarily due to major maintenance activities completed in the first quarter of 2019. NGL fractionation volumes at our Hobbs NGL fractionator increased 12 MBPD year-to-year.

Crude Oil Pipelines & Services

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

	For the Year Ended December 31,	
	2020	2019
Segment gross operating margin:		
Midland-to-ECHO System:		
Midland-to-ECHO System and related business activities, excluding associated non-cash mark-to-market results	$ 359.5	$ 463.0
Midland-to-ECHO 1 non-cash mark-to-market gains (losses)	(0.3)	88.4
Total Midland-to-ECHO System	359.2	551.4
Other crude oil pipelines, terminals and related marketing results	1,638.1	1,536.4
Total	$ 1,997.3	$ 2,087.8
Selected volumetric data: (1)		
Crude oil pipeline transportation volumes (MBPD)	2,166	2,304
Crude oil marine terminal volumes (MBPD)	724	964

(1) In general, segment volumes for the year ended December 31, 2020 were adversely impacted by the reduction in upstream crude oil production activities caused by the COVID-19 pandemic and crude oil price shock.

Gross operating margin from our Crude Oil Pipelines & Services segment for the year ended December 31, 2020 decreased $90.5 million when compared to the year ended December 31, 2019.

Gross operating margin from our Midland-to-ECHO System and related business activities decreased $192.2 million year-to-year primarily due to lower average sales margins from marketing activities (including the impact of hedging activities) of $217.2 million. Gross operating margin from our Midland-to-ECHO 3 pipeline, which commenced operations in October 2020, was $30.0 million with transportation volumes of 214 MBPD.

Gross operating margin from our South Texas Crude Oil Pipeline System decreased $50.0 million year-to-year primarily due to lower transportation volumes, which accounted for a $32.4 million decrease, and lower transportation and other fees, which accounted for an additional $23.5 million decrease. Gross operating margin from our equity investment in the Eagle Ford Crude Oil Pipeline decreased $24.2 million year-to-year primarily due to lower transportation volumes. On an aggregate basis, transportation volumes on these two pipeline systems decreased a combined 68 MBPD year-to-year (net to our interest).

Gross operating margin from our equity investment in the Seaway Pipeline decreased $53.2 million year-to-year primarily due to lower average transportation fees, which accounted for a $36.7 million decrease, and lower transportation volumes, which accounted for an additional $18.9 million decrease. Net to our interest, transportation and marine terminal volumes for the Seaway Pipeline decreased 164 MBPD and 32 MBPD, respectively, year-to-year.

Gross operating margin from our ECHO terminal decreased $25.9 million year-to-year primarily due to lower terminaling and storage revenue, which accounted for a $16.6 million decrease, and a benefit recognized during the second quarter of 2019 in connection with a settlement, which accounted for an additional $13.9 million decrease.

Gross operating margin from our other crude oil marketing activities increased $225.8 million year-to-year primarily due to higher average sales margins (including the impact of hedging activities). The year-to-year increase in gross operating margin from these activities is primarily due to results from marketing strategies that seek to optimize our storage assets.

Gross operating margin from crude oil activities at EHT increased $15.3 million year-to-year primarily due to higher storage revenues. Crude oil terminal volumes at EHT decreased by 164 MBPD year-to-year. Lastly, gross operating margin from our EFS Midstream system increased $13.4 million year-to-year primarily due to higher average transportation fees.

Natural Gas Pipelines & Services

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

	For the Year Ended December 31,	
	2020	**2019**
Segment gross operating margin	$ 926.6	$ 1,062.6
Selected volumetric data:		
Natural gas pipeline transportation volumes (BBtus/d)	13,421	14,198

Gross operating margin from our Natural Gas Pipelines & Services segment for the year ended December 31, 2020 decreased $136.0 million when compared to the year ended December 31, 2019.

Gross operating margin from our Acadian Gas System decreased $45.4 million year-to-year primarily due to lower capacity reservation revenues on the Haynesville Extension pipeline, which accounted for a $32.5 million decrease, and lower net benefits from settlements, which accounted for an additional $15.4 million decrease. Transportation volumes on our Acadian Gas System decreased 144 BBtus/d year-to-year. Gross operating margin from our Texas Intrastate System decreased $36.8 million year-to-year primarily due to lower capacity reservation revenues. Transportation volumes on our Texas Intrastate System decreased 171 BBtus/d year-to-year. Gross operating margin from our Haynesville Gathering System decreased $19.9 million year-to-year primarily due to lower gathering volumes of 211 BBtus/d, which accounted for a $14.4 million decrease, and lower average gathering fees, which accounted for an additional $4.9 million decrease.

On a combined basis, gross operating margin from our Jonah Gathering System, Piceance Basin Gathering System, and San Juan Gathering System in the Rocky Mountains decreased a net $17.2 million year-to-year primarily due to lower volumes of 492 BBtus/d, which accounted for a $44.9 million decrease, partially offset by higher average fees, which accounted for a $22.5 million increase.

Gross operating margin from our natural gas marketing activities decreased $51.1 million year-to-year primarily due to lower average sales margins (including the impact of hedging activities), which accounted for a $37.0 million decrease, and lower sales volumes, which accounted for an additional $14.1 million decrease.

Gross operating margin from our Permian Basin Gathering System increased $34.3 million year-to-year primarily due to a 456 BBtus/d increase in natural gas gathering volumes.

Petrochemical & Refined Products Services

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

	For the Year Ended December 31,	
	2020	**2019**
Segment gross operating margin:		
Propylene production and related activities	$ 471.0	$ 445.1
Butane isomerization and related operations	67.6	79.9
Octane enhancement and related plant operations	161.7	166.0
Refined products pipelines and related activities	318.6	330.8
Ethylene exports and other services	62.9	47.8
Total	$ 1,081.8	$ 1,069.6
Selected volumetric data:		
Propylene production volumes (MBPD)	89	97
Butane isomerization volumes (MBPD)	96	109
Standalone DIB processing volumes (MBPD)	127	99
Octane enhancement and related plant sales volumes (MBPD) (1)	35	32
Pipeline transportation volumes, primarily refined products and petrochemicals (MBPD)	802	739
Marine terminal volumes, primarily refined products and petrochemicals (MBPD)	262	325

(1) Reflects aggregate sales volumes for our octane additive and iBDH facilities located at our Mont Belvieu complex and our HPIB facility located adjacent to the Houston Ship Channel.

Propylene production and related activities

Gross operating margin from propylene production and related activities for the year ended December 31, 2020 increased $25.9 million when compared to the year ended December 31, 2019.

Gross operating margin from our propylene production facilities increased a combined $14.1 million year-to-year primarily due to lower operating costs, which accounted for an $18.9 million increase, and higher exchange and storage fee revenues, which accounted for an additional $15.6 million increase, partially offset by lower propylene and associated by-product sales volumes, which accounted for a $23.6 million decrease. Propylene production volumes at these facilities decreased a combined 6 MBPD year-to-year (net to our interest). As refiners reduced their utilization rates in response to lower demand for refined products caused by the COVID-19 pandemic, there was a decrease in the availability of refinery grade propylene feedstock used by our facilities to create polymer grade propylene. As a result, our propylene production volumes were reduced, with the largest impacts occurring in the second quarter of 2020.

Gross operating margin from our propylene export terminals increased $10.2 million year-to-year primarily due to higher average terminal fees. Propylene export volumes decreased 3 MBPD year-to-year.

Isomerization and related operations

Gross operating margin from isomerization and related operations decreased a net $12.3 million year-to-year primarily due to lower average by-product sales prices, which accounted for a $21.9 million decrease, and lower isomerization volumes of 13 MBPD, which accounted for an additional $9.5 million decrease, partially offset by lower operating costs, which accounted for a $19.7 million increase.

Octane enhancement and related plant operations

Gross operating margin from our octane enhancement and related plant operations decreased a net $4.3 million year-to-year primarily due to lower average sales margins, which accounted for a $23.4 million decrease, and higher operating costs, which accounted for an additional $13.5 million decrease, partially offset by higher sales volumes, which accounted for a $27.6 million increase. The increase in operating expenses is primarily due to our iBDH plant, which is integrated with our legacy octane enhancement and high purity isobutylene assets and was placed into service in December 2019.

Refined products pipelines and related activities
Gross operating margin from refined products pipelines and related activities for the year ended December 31, 2020 decreased $12.2 million when compared to the year ended December 31, 2019.

Gross operating margin from our TE Products Pipeline System and associated terminals decreased a combined $37.3 million year-to-year primarily due to lower interstate refined products transportation volumes, which accounted for a $12.5 million decrease, and lower NGL transportation volumes, which accounted for a $12.0 million decrease, higher operating costs, which accounted for a $3.8 million decrease, and lower average intrastate refined products transportation fees, which accounted for an additional $2.7 million decrease. Overall transportation volumes on our TE Products Pipeline System increased a net 34 MBPD year-to-year.

Gross operating margin from our refined products terminal in Beaumont, Texas decreased a net $7.1 million year-to-year primarily due to lower storage revenues, which accounted for a $14.5 million decrease, partially offset by lower operating costs, which accounted for a $9.4 million increase. Marine terminal volumes at Beaumont decreased 53 MBPD year-to-year.

Gross operating margin from our refined products marketing activities increased $27.4 million year-to-year primarily due to higher sales volumes.

Ethylene exports and other services
Gross operating margin from ethylene exports and other services for the year ended December 31, 2020 increased $15.1 million when compared to the year ended December 31, 2019. Gross operating margin from our ethylene export terminal and its related operations was a combined $25.6 million for 2020. Our ethylene export terminal and associated infrastructure were placed into limited service in December 2019 and full service in December 2020. Loading volumes at our ethylene export terminal for 2020 were 10 MBPD (net to our interest).

Gross operating margin from marine transportation services decreased $12.4 million year-to-year primarily due to lower average fleet utilization rates in 2020.

Liquidity and Capital Resources

Based on current market conditions (as of the filing date of this annual report), we believe that the Partnership and its consolidated businesses will have sufficient liquidity, cash flow from operations and access to capital markets to fund their capital investments and working capital needs for the reasonably foreseeable future. At December 31, 2020, we had $6.06 billion of consolidated liquidity, which was comprised of $5.0 billion of available borrowing capacity under EPO's revolving credit facilities and $1.06 billion of unrestricted cash on hand.

We may issue debt and equity securities to assist us in meeting our future funding and liquidity requirements, including those related to capital investments. We have a universal shelf registration statement (the "2019 Shelf") on file with the SEC which allows the Partnership and EPO to issue an unlimited amount of equity and debt securities, respectively.

Enterprise Declares Cash Distribution for Fourth Quarter of 2020

On January 7, 2021, we announced that the Board declared a quarterly cash distribution of $0.45 per common unit, or $1.80 per unit on an annualized basis, to be paid to the Partnership's common unitholders with respect to the fourth quarter of 2020. The quarterly distribution was paid on February 11, 2021 to unitholders of record as of the close of business on January 29, 2021. The total amount paid was $988.8 million, which includes $7.1 million for distribution equivalent rights on phantom unit awards.

In light of current economic conditions, management will evaluate any future increases in cash distributions on a quarterly basis. The payment of any quarterly cash distribution is subject to management's evaluation of our financial condition, results of operations and cash flows in connection with such payments and Board approval.

Consolidated Debt

At December 31, 2020, the average maturity of EPO's consolidated debt obligations was approximately 20.4 years. The following table presents the scheduled maturities of principal amounts of EPO's consolidated debt obligations at December 31, 2020 for the years indicated (dollars in millions):

	Total	2021	2022	2023	2024	2025	Thereafter
Principal amount of senior and junior debt obligations	$ 30,146.4	$ 1,325.0	$ 1,400.0	$ 1,250.0	$ 850.0	$ 1,150.0	$ 24,171.4

In January 2020, EPO issued $3.0 billion aggregate principal amount of senior notes comprised of (i) $1.0 billion principal amount of 2.80% fixed-rate senior notes due January 2030 ("Senior Notes AAA"), (ii) $1.0 billion principal amount of 3.70% fixed-rate senior notes due January 2051 ("Senior Notes BBB") and (iii) $1.0 billion principal amount of 3.95% fixed-rate senior notes due January 2060 ("Senior Notes CCC"). Net proceeds from this offering were used by EPO for the repayment of $500 million principal amount of its Senior Notes Q that matured in January 2020, temporary repayment of amounts outstanding under its commercial paper program and for general company purposes. In addition, net proceeds from this offering were used by EPO for the repayment of $1.0 billion principal amount of its Senior Notes Y that matured in September 2020.

In August 2020, EPO issued $1.0 billion principal amount of 3.20% fixed-rate senior notes due February 2052 ("Senior Notes DDD") and $250.0 million principal amount of reopened 2.80% fixed-rate Senior Notes AAA. We received aggregate net proceeds of $1.25 billion from the sale of the notes after deducting underwriting discounts and other estimated offering expenses payable by us. Net proceeds from the issuance of these senior notes were used for general company purposes, including for growth capital investments, and to repay a portion of the $750.0 million in principal amount of Senior Notes TT that matured in February 2021.

In September 2020, EPO entered into a new 364-Day Revolving Credit Agreement that replaced its September 2019 364-Day Revolving Credit Agreement. The new 364-Day Revolving Credit Agreement matures in September 2021. There was no principal amount outstanding under the September 2019 364-Day Revolving Credit Agreement when it expired and was replaced by the September 2020 364-Day Revolving Credit Agreement.

In February 2021, EPO notified its trustee and paying agent to redeem all of the $575.0 million outstanding principal amount of its Senior Notes RR effective as of March 15, 2021 (one month prior to their scheduled maturity in April 2021). These notes are redeemable at EPO's election at par (i.e., at a redemption price equal to the outstanding principal amount of such notes to be redeemed, plus accrued and unpaid interest thereon). On a short term basis, the redemption of EPO's Senior Notes RR is expected to be made using proceeds from the issuance of short term notes under EPO's commercial paper program.

For additional information regarding our consolidated debt obligations, see Note 7 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Credit Ratings

As of March 1, 2021, the investment-grade credit ratings of EPO's long-term senior unsecured debt securities were BBB+ from Standard and Poor's, Baa1 from Moody's and BBB+ from Fitch Ratings. In addition, the credit ratings of EPO's short-term senior unsecured debt securities were A-2 from Standard and Poor's, P-2 from Moody's and F-2 from Fitch Ratings. EPO's credit ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any of our securities. A credit rating can be revised upward or downward or withdrawn at any time by a rating agency, if it determines that circumstances warrant such a change. A credit rating from one rating agency should be evaluated independently of credit ratings from other rating agencies.

Common Unit Repurchases Under 2019 Buyback Program

In January 2019, we announced that the Board had approved a $2.0 billion multi-year unit buyback program (the "2019 Buyback Program"), which provides us with an additional method to return capital to investors. The 2019 Buyback 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) the market price of the Partnership's common units and implied cash flow yield and (iv) maintaining targeted financial leverage, which is currently a debt-to-normalized adjusted EBITDA (earnings before interest, taxes, depreciation and amortization) ratio in the range of 3.25 to 3.75 times. No time limit has been set for completion of the 2019 Buyback Program, and it may be suspended or discontinued at any time.

We repurchased an aggregate 8,978,317 common units under the 2019 Buyback Program through open market and private purchases during the year ended December 31, 2020. The total purchase price of these repurchases was $186.3 million including commissions and fees. Units repurchased under the 2019 Buyback Program are immediately cancelled upon acquisition. As of December 31, 2020, the remaining available capacity under the 2019 Buyback Program was $1.73 billion.

In addition to the 2019 Buyback Program, privately held affiliates of EPCO acquired 1,459,000 of our common units on the open market during the year ended December 31, 2020. In the aggregate, 10,437,317 common units were purchased on the open market during the year ended December 31, 2020 under the 2019 Buyback Program and by privately held affiliates of EPCO.

Issuance of Common Units due to Settlement of Liquidity Option in March 2020

On March 5, 2020, we settled our obligations under the Liquidity Option Agreement by issuing 54,807,352 new common units to Skyline North Americas, Inc. in exchange for the capital stock of OTA. Upon settlement of the Liquidity Option, we indirectly acquired the 54,807,352 Partnership common units owned by OTA (which were issued by us to OTA in October 2014) and assumed all future income tax obligations of OTA, including its deferred tax liability. For additional information regarding settlement of the Liquidity Option, see Note 8 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

September 2020 Issuance of Series A Cumulative Convertible Preferred Units

On September 30, 2020, we issued and sold an aggregate of 50,000 Series A Cumulative Convertible Preferred Units in a private placement transaction. The stated value of each preferred unit is $1,000 per unit. The total offering price for the preferred units was $50.0 million, of which $32.5 million was received in cash with the remaining $17.5 million funded through the exchange of 1,120,588 of our common units owned by the purchasers. Cash proceeds from the preferred unit offering include $15.0 million received from a privately held affiliate of EPCO for the purchase of 15,000 preferred units. Offering expenses were approximately $1.0 million.

Concurrently, we exchanged all of the 54,807,352 Partnership common units owned directly by OTA for 855,915 of our new preferred units having an equivalent value. The preferred units held by OTA, like the common units OTA held prior to the exchange, are accounted for as treasury units by us in consolidation. The historical cost of the treasury units did not change as a result of the exchange and remains at the $1.3 billion recognized in March 2020 in connection with settlement of the Liquidity Option.

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

Cash Flow Statement Highlights

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the years indicated (dollars in millions).

	For the Year Ended December 31,	
	2020	**2019**
Net cash flows provided by operating activities	$ 5,891.5	$ 6,520.5
Cash used in investing activities	3,120.7	4,575.5
Cash used in financing activities	2,022.7	1,945.1

Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. Changes in energy commodity prices may impact the demand for natural gas, NGLs, crude oil, petrochemical and refined products, which could impact sales of our products and the demand for our midstream services. Changes in demand for our products and services may be caused by other factors, including prevailing economic conditions, reduced demand by consumers for the end products made with hydrocarbon products, increased competition, public health emergencies, 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 contractual obligations to us in connection with our marketing activities and long-term take-or-pay agreements. For a more complete discussion of these and other risk factors pertinent to our business, see Part I, Item 1A of this annual report.

For additional information regarding our cash flow amounts, please refer to the Statements of Consolidated Cash Flows included under Part II, Item 8 of this annual report.

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

<u>Operating activities</u>
Net cash flows provided by operating activities for the year ended December 31, 2020 decreased $629.0 million when compared to the year ended December 31, 2019 primarily due to:

- a $310.1 million year-to-year decrease primarily due to higher levels of working capital employed in our marketing activities, which accounted for a $1.4 billion decrease, partially offset by the timing of cash receipts and payments related to operations;

- a $177.5 million year-to-year decrease resulting from lower partnership earnings in 2020 when compared to 2019 (determined by adjusting our $801.4 million year-to-year decrease in net income for changes in the non-cash items identified on our Statements of Consolidated Cash Flows); and

- a $141.4 million year-to-year decrease in cash distributions attributable to earnings from unconsolidated affiliates, with those unconsolidated affiliates owning crude oil pipelines and terminals accounting for substantially all of the decrease.

For information regarding significant year-to-year changes in our consolidated net income and underlying segment results, see "*Income Statement Highlights*" and "*Business Segment Highlights*" within this Part II, Item 7.

<u>Investing activities</u>
Cash used in investing activities for the year ended December 31, 2020 decreased $1.45 billion when compared to the year ended December 31, 2019 primarily due to:

- a $1.24 billion year-to-year decrease in investments for property, plant and equipment (see "*Capital Investments*" within this Part II, Item 7 for additional information);

- a $124.2 million year-to-year increase in cash distributions attributable to the return of capital from unconsolidated affiliates, with those unconsolidated affiliates owning crude oil pipelines and terminals accounting for a majority of the increase; and

- a $96.0 million year-to-year decrease in investments in unconsolidated affiliates primarily due to lower cash outlays for NGL and crude oil pipeline projects.

Financing activities
Cash used in financing activities for the year ended December 31, 2020 increased a net $77.6 million when compared to the year ended December 31, 2019 primarily due to:

- a $601.9 million year-to-year decrease in cash contributions from noncontrolling interests. In July 2019, an affiliate of Apache Corporation acquired a noncontrolling 33% equity interest in our consolidated subsidiary that owns the Shin Oak NGL Pipeline for $440.7 million. In addition, cash contributions from noncontrolling interests in connection with our Pascagoula natural gas processing plant and ethylene export facility decreased a combined $105.5 million year-to-year;

- a $105.2 million year-to-year increase in cash used to acquire common units under our 2019 Buyback Program;

- an $82.2 million year-to-year decrease in net cash proceeds from the issuance of common units under our distribution reinvestment plan ("DRIP") and employee unit purchase plan ("EUPP"). In July 2019, the Partnership announced that, beginning with the quarterly distribution payment paid in August 2019, it would use common units purchased on the open market, rather than issuing new common units, to satisfy its delivery obligations under the DRIP and EUPP; and

- a $51.2 million year-to-year increase in cash distributions paid to common unitholders attributable to increases in the quarterly cash distribution rate per unit; partially offset by

- a net $757.4 million year-to-year increase in net cash inflows from debt. In 2020, we issued $4.25 billion aggregate principal amount of senior notes, partially offset by the repayment of $1.5 billion principal amount of senior notes. In 2019, we issued $2.5 billion aggregate principal amount of senior notes, partially offset by the repayment or repurchase of $1.52 billion principal amount of senior and junior subordinated notes. In addition, net repayments of short term notes under EPO's commercial paper program were $481.8 million in 2020 compared to net issuances of $481.8 million in 2019; and

- a $31.5 million increase in net cash proceeds from the issuance of preferred units in September 2020.

Non-GAAP Cash Flow Measures

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

We measure available cash by reference to distributable cash flow ("DCF"), which is a non-GAAP cash flow measure. DCF is an important financial measure for our common unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flows at a level that can sustain our declared quarterly cash distributions. DCF is also a quantitative standard used by the investment community with respect to publicly traded partnerships since the value of a partnership unit is, in part, measured by its yield, which is based on the amount of cash distributions a partnership can pay to a unitholder. Our management compares the DCF we generate to the cash distributions we expect to pay our common unitholders. Using this metric, management computes our distribution coverage ratio. Our calculation of DCF may or may not be comparable to similarly titled measures used by other companies.

Based on the level of available cash each quarter, management proposes a quarterly cash distribution rate to the Board of Enterprise GP, which has sole authority in approving such matters. Unlike several other master limited partnerships, our general partner has a non-economic ownership interest in us and is not entitled to receive any cash distributions from us based on incentive distribution rights or other equity interests.

Our use of DCF for the limited purposes described above and in this report is not a substitute for net cash flows provided by operating activities, which is the most comparable GAAP measure. For a discussion of net cash flows provided by operating activities, see "Cash Flow Statement Highlights" within this Part II, Item 7.

The following table summarizes our calculation of DCF for the years indicated (dollars in millions):

	For the Year Ended December 31, 2020	2019
Net income attributable to common unitholders (GAAP) (1)	$ 3,774.7	$ 4,591.3
Adjustments to net income attributable to common unitholders to derive DCF (addition or subtraction indicated by sign):		
Depreciation, amortization and accretion expenses	2,071.9	1,949.3
Cash distributions received from unconsolidated affiliates (2)	614.1	631.3
Equity in income of unconsolidated affiliates	(426.1)	(563.0)
Asset impairment and related charges	890.6	132.8
Change in fair market value of derivative instruments	(79.3)	27.2
Change in fair value of Liquidity Option	2.3	119.6
Deferred income tax expense (benefit)	(147.6)	20.0
Sustaining capital expenditures (3)	(293.6)	(325.2)
Other, net	20.2	20.0
Operational DCF (4)	$ 6,427.2	$ 6,603.3
Proceeds from asset sales	12.8	20.6
Monetization of interest rate derivative instruments accounted for as cash flow hedges	(33.3)	–
DCF (non-GAAP)	$ 6,406.7	$ 6,623.9
Cash distributions paid to common unitholders with respect to period, including distribution equivalent rights on phantom unit awards	$ 3,926.9	$ 3,887.0
Cash distribution per common unit declared by Enterprise GP with respect to period (5)	$ 1.7850	$ 1.7650
Total DCF retained by the Partnership with respect to period (6)	$ 2,479.8	$ 2,736.9
Distribution coverage ratio (7)	1.63x	1.70x

(1) For a discussion of the primary drivers of changes in our comparative income statement amounts, see "Income Statement Highlights" within this Part II, Item 7.

(2) Reflects distributions received from unconsolidated affiliates attributable to earnings and the return of capital.

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

(4) Represents DCF before proceeds from asset sales and the monetization of interest rate derivative instruments accounted for as cash flow hedges.

(5) See Note 8 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding our quarterly cash distributions declared with respect to the years indicated.

(6) At the sole discretion of Enterprise GP, cash retained by the partnership with respect to each of these periods was primarily reinvested in growth capital projects. This retainage of cash substantially reduced our reliance on the equity capital markets to fund such expenditures.

(7) Distribution coverage ratio is determined by dividing DCF by total cash distributions paid to common unitholders and in connection with distribution equivalent rights with respect to the period.

The following table presents a reconciliation of net cash flows provided by operating activities to DCF for the years indicated (dollars in millions):

	For the Year Ended December 31, 2020	For the Year Ended December 31, 2019
Net cash flows provided by operating activities (GAAP)	$ 5,891.5	$ 6,520.5
Adjustments to reconcile net cash flows provided by operating activities to DCF (addition or subtraction indicated by sign):		
Net effect of changes in operating accounts	767.5	457.4
Sustaining capital expenditures	(293.6)	(325.2)
Distributions received from unconsolidated affiliates attributable to the return of capital	187.5	63.3
Proceeds from asset sales	12.8	20.6
Net income attributable to noncontrolling interest	(110.1)	(95.8)
Monetization of interest rate derivative instruments accounted for as cash flow hedges	(33.3)	–
Other, net	(15.6)	(16.9)
DCF (non-GAAP)	$ 6,406.7	$ 6,623.9

Free Cash Flow

Free Cash Flow ("FCF"), a non-GAAP financial measure, is a traditional cash flow metric that is widely used by a variety of investors and other participants in the financial community, as opposed to DCF, which is a cash flow measure primarily used by investors and others in evaluating midstream energy companies, including master limited partnerships. In general, FCF is a measure of how much cash flow a business generates during a specified time period after accounting for all capital investments, including expenditures for growth and sustaining capital projects. By comparison, only sustaining capital expenditures are reflected in DCF.

We believe that FCF is important to traditional investors since it reflects the amount of cash available for reducing debt, investing in additional capital projects, paying distributions, common unit repurchases and similar matters. Since business partners fund certain capital projects of our consolidated subsidiaries, our determination of FCF reflects the amount of cash contributed from and distributed to noncontrolling interests. Our calculation of FCF may or may not be comparable to similarly titled measures used by other companies.

Our use of FCF for the limited purposes described above and in this report is not a substitute for net cash flows provided by operating activities, which is the most comparable GAAP measure.

FCF fluctuates based on our earnings, the level of investing activities we undertake each period, and the timing of operating cash receipts and payments. The following table summarizes our calculation of FCF for the years indicated (dollars in millions):

	For the Year Ended December 31, 2020	For the Year Ended December 31, 2019
Net cash flows provided by operating activities (GAAP)	$ 5,891.5	$ 6,520.5
Adjustments to net cash flows provided by operating activities to derive FCF (addition or subtraction indicated by sign):		
Cash used in investing activities	(3,120.7)	(4,575.5)
Cash contributions from noncontrolling interests	30.9	632.8
Cash distributions paid to noncontrolling interests	(131.3)	(106.2)
FCF (non-GAAP)	$ 2,670.4	$ 2,471.6

The elements used in calculating FCF are sourced directly from our statements of consolidated cash flows presented under Part II, Item 8 of this annual report. For a discussion of significant year-to-year changes in our cash flow statement amounts, see "Cash Flow Statement Highlights" within this Part II, Item 7.

Capital Investments

The following table summarizes our capital investments for the years indicated (dollars in millions):

	For the Years Ended December 31, 2020	For the Years Ended December 31, 2019
Capital investments for property, plant and equipment: (1)		
Growth capital projects (2)	$ 2,985.8	$ 4,208.1
Sustaining capital projects (3)	302.1	323.6
Total	$ 3,287.9	$ 4,531.7
Investments in unconsolidated affiliates	$ 15.6	$ 111.6

(1) Growth and sustaining capital amounts presented in the table above are presented on a cash basis. In total, these amounts represent "Capital expenditures" as presented on our Statements of Consolidated Cash Flows.

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

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

We placed a number of growth capital projects into commercial service during 2020 including:

- Frac X and Frac XI in March 2020 and September 2020, respectively;
- expansion projects on the Texas Express Pipeline and Front Range Pipeline in April 2020;
- the Midland-to-ECHO segment of the Midland-to-Webster pipeline in October 2020; and
- refrigerated storage at our ethylene export terminal in December 2020.

We currently have $3.6 billion of growth capital projects scheduled to be completed by the end of 2023, which includes completion of a natural gasoline hydrotreater facility at our Mont Belvieu-area complex in the fourth quarter of 2021, the Gillis Lateral natural gas pipeline and related infrastructure in the fourth quarter of 2021, and our PDH 2 facility in the second quarter of 2023.

Capital investing activity throughout the domestic energy industry has been significantly reduced in response to the supply and demand disruptions caused by the COVID-19 pandemic. In light of these adverse macroeconomic conditions, we discussed with our customers and reevaluated our planned capital investments in order to modify the capacity, timing and need for certain capital projects and to maximize available liquidity. Based on information currently available, we expect our total capital investments for 2021, net of contributions from joint venture partners, to approximate $2.1 billion, which reflects growth capital investments of $1.6 billion and sustaining capital expenditures of $440 million. In addition, we currently expect our growth capital investments in 2022 and 2023 for sanctioned projects to approximate $800 million and $400 million, respectively. These amounts do not include capital investments associated with SPOT, our proposed deepwater offshore crude oil terminal, which remains subject to governmental approvals. We currently anticipate receiving approval for SPOT as early as the third quarter of 2021; however, we can give no assurance as to whether the project will ultimately be approved or the timing of such decision.

Our forecast of capital investments for 2021 through 2023 is based on announced strategic operating and growth plans (through the filing date of this quarterly report), which are dependent upon our ability to generate the required funds from either operating cash flows or other means, including borrowings under debt agreements, the issuance of additional equity and debt securities, and potential divestitures. We may revise our forecast of capital investments due to factors beyond our control, such as adverse economic conditions, weather-related issues and changes in supplier prices. Furthermore, our forecast of capital investments may change due to decisions made by management at a later date, which may include unforeseen acquisition opportunities. Our success in raising capital, including partnering with other companies to share project costs and risks, continues to be a significant factor in determining how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future growth needs and, although we expect to make the forecast capital investments noted above, we may adjust the timing and amounts of projected expenditures in response to changes in capital market conditions.

Comparison of Year Ended December 31, 2020 with Year Ended December 31, 2019

In total, investments in growth capital projects decreased $1.2 billion year-to-year primarily due to the following:

- completion of projects at our Mont Belvieu complex, which accounted for a $759.7 million decrease and included placing into service our iBDH facility (December 2019), Frac X (March 2020) and Frac XI (September 2020);
- lower investments in natural gas processing facilities and related infrastructure that support Permian Basin production, which accounted for a $372.4 million decrease. We completed the final phase of our Orla plant in July 2019 and placed our Mentone plant into service in December 2019;
- completion of the Shin Oak NGL Pipeline (in stages through the fourth quarter of 2019), which accounted for a $353.2 million decrease; and
- lower investments in projects attributable to our ethylene business, which accounted for a $175.3 million decrease; partially offset by,
- higher investments in our PDH 2 facility, which accounted for a $335.7 million increase;
- higher investments in crude oil pipelines, including those expanding our Midland-to-ECHO System, and related infrastructure that support Permian Basin production, which accounted for a combined $82.2 million increase; and
- higher investments in natural gas pipelines and related infrastructure in support of East Texas and Louisiana production, which accounted for a $47.9 million increase.

Investments in unconsolidated affiliates decreased $96.0 million year-to-year primarily due to lower spending on NGL pipeline expansion projects, which accounted for a $49.4 million decrease, and lower spending on our joint venture dock infrastructure at Corpus Christi and other crude oil-related projects, which accounted for an additional $44.2 million decrease.

Fluctuations in investments for sustaining capital projects are primarily due to the timing and cost of pipeline integrity and similar projects.

Critical Accounting Policies and Estimates

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

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

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

At December 31, 2020 and 2019, the net carrying value of our property, plant and equipment was $41.91 billion and $41.6 billion, respectively. We recorded $1.68 billion and $1.56 billion of depreciation expense during the years ended December 31, 2020 and 2019, respectively. For information regarding our property, plant and equipment, see Note 4 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

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

Long-lived assets, which consist of intangible assets with finite useful lives and property, plant and equipment, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable through future cash flows. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand for or price of natural gas, NGLs, crude oil, petrochemicals or refined products.

The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the asset. Estimates of undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated residual values. If the carrying value of a long-lived asset is not recoverable, an impairment charge would be recorded for the excess of the asset's carrying value over its estimated fair value, which is derived from an analysis of the asset's estimated future cash flows, the market value of similar assets and replacement cost of the asset less any applicable depreciation or amortization. In addition, fair value estimates also include the usage of probabilities when there is a range of possible outcomes.

We evaluate our equity method investments for impairment when there are events or changes in circumstances that indicate there is a potential loss in value of the investment attributable to an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the entity and/or long-term negative changes in the entity's industry. In the event we determine that the value of an investment is not recoverable due to an other than temporary decline, we record a non-cash impairment charge to adjust the carrying value of the investment to its estimated fair value. We assess the fair value of our equity method investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party sales and discounted estimated cash flow models. Estimates of discounted cash flows are based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful lives of the investment's underlying assets.

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

In 2020 and 2019, we recognized non-cash asset impairment charges attributable to assets other than goodwill totaling $594.3 million and $132.8 million, respectively, which are a component of operating costs and expenses. For information regarding impairment charges involving property, plant and equipment and investments in unconsolidated affiliates, see Notes 4 and 5, respectively, of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Valuation and Amortization Methods of Customer Relationships and Contract-Based Intangible Assets

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

Customer relationship intangible assets represent the estimated economic value assigned to commercial relationships acquired in connection with business combinations. In certain instances, the acquisition of these intangible assets provides us with access to customers in a defined resource basin and is analogous to having a franchise in a particular area. Efficient operation of the acquired assets (e.g., a natural gas gathering system) helps to support the commercial relationships with existing producers and provides us with opportunities to establish new ones within our existing asset footprint. The duration of this type of customer relationship is limited by the estimated economic life of the associated resource basin that supports the customer group. When estimating the economic life of a resource basin, we consider a number of factors, including reserve estimates and the economic viability of production and exploration activities.

In other situations, the acquisition of a customer relationship intangible asset provides us with access to customers whose hydrocarbon volumes are not attributable to specific resource basins. As with basin-specific customer relationships, efficient operation of the associated assets (e.g., a marine terminal that handles volumes originating from multiple sources) helps to support the commercial relationships with existing customers and provides us with opportunities to establish new ones. The duration of this type of customer relationship is typically limited to the term of the underlying service contracts, including assumed renewals.

The value we assign to customer relationships is amortized to earnings using methods that closely resemble the pattern in which the estimated economic benefits will be consumed (i.e., the manner in which the intangible asset is expected to contribute directly or indirectly to our cash flows). For example, the amortization period for a basin-specific customer relationship asset is limited by the estimated finite economic life of the associated hydrocarbon resource basin.

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

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

At December 31, 2020 and 2019, the carrying value of our customer relationship and contract-based intangible asset portfolio was \$3.31 billion and \$3.45 billion, respectively. We recorded \$143.2 million and \$174.7 million of amortization expense attributable to intangible assets during the years ended December 31, 2020 and 2019, respectively. For information regarding our intangible assets, see Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

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

Our goodwill balance was \$5.45 billion and \$5.75 billion at December 31, 2020 and 2019, respectively. Goodwill, which represents the cost of an acquired business in excess of the fair value of its net assets at the acquisition date, is subject to annual impairment testing in the fourth quarter of each year or when events or changes in circumstances indicate that the carrying amount of the goodwill may not be recoverable. Goodwill impairment charges represent the amount by which a reporting unit's carrying value (including its respective goodwill) exceeds its fair value, not to exceed the carrying amount of the reporting unit's goodwill.

We determine the fair value of each reporting unit using accepted valuation techniques, primarily through the use of discounted cash flows (i.e., an income approach to fair value) supplemented by market-based assessments, if available. The estimated fair values of our reporting units incorporate assumptions regarding the future economic prospects of the assets and operations that comprise each reporting unit including: (i) discrete financial forecasts for the assets comprising the reporting unit, which, in turn, rely on management's estimates of long-term operating margins, throughput volumes, capital investments and similar factors; (ii) long-term growth rates for the reporting unit's cash flows beyond the discrete forecast period; and (iii) appropriate discount rates. The fair value estimates are based on Level 3 inputs of the fair value hierarchy. We believe that the assumptions we use in estimating reporting unit fair values are consistent with those that market participants would use in their fair value estimation process. However, due to uncertainties in the estimation process and volatility in the supply and demand for hydrocarbons and similar risk factors, actual results could differ significantly from our estimates.

In December 2020, management determined that the carrying value of our natural gas pipelines and services reporting unit exceeded its estimated fair value. This reporting unit, which reflects the operations of our Natural Gas Pipelines & Services business segment, includes our natural gas gathering and transmission pipelines, storage facilities and related marketing activities. The long-term outlook for natural gas production in certain supply basins such as the Rocky Mountains and East Texas is expected to remain lower for longer due to reduced drilling activity. In addition, the decline in pipeline revenues attributable to lower regional natural gas price spreads is expected to adversely impact the future cash flows of our transmission pipelines. These factors, coupled with an increase in the estimated rate of return required for such businesses by market participants, resulted in the fair value of this reporting unit being less than its carrying value at December 31, 2020. The resulting goodwill impairment charge of $296.3 million represents the entire amount of goodwill attributable to this reporting unit.

We did not record any goodwill impairment charges during the year ended December 31, 2019. Based on our most recent goodwill impairment test at December 31, 2020, the estimated fair value of each of our reporting units, with the exception of our natural gas pipelines and services reporting unit, was at least 10% in excess of its carrying value.

For information regarding our goodwill, see Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Use of Estimates for Revenues and Expenses

As noted previously, preparing our consolidated financial statements in conformity with GAAP requires us to make estimates that affect amounts presented in the financial statements. Due to the time required to compile actual billing information and receive third party data needed to record transactions, we routinely employ estimates in connection with revenue and expense amounts in order to meet our accelerated financial reporting deadlines.

Our most significant routine estimates involve revenues and costs of certain natural gas processing facilities, pipeline transportation revenues, fractionation revenues, marketing revenues and related purchases, and power and utility costs. These types of transactions must be estimated since the actual amounts are generally unavailable at the time we complete our accounting close process. The estimates subsequently reverse in the next accounting period when the corresponding actual customer billing or vendor-invoiced amounts are recorded.

Changes in facts and circumstances may result in revised estimates, which could affect our reported financial statements and accompanying disclosures. Prior to issuing our financial statements, we review our revenue and expense estimates based on currently available information to determine if adjustments are required. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect.

Other Matters

Parent-Subsidiary Guarantor Relationship

The Partnership (the "Parent Guarantor") has guaranteed the payment of principal and interest on the consolidated debt obligations of EPO (the "Subsidiary Issuer"), with the exception of the remaining debt obligations of TEPPCO Partners, L.P. (collectively, the "Guaranteed Debt"). If EPO were to default on any of its Guaranteed Debt, the Partnership would be responsible for full and unconditional repayment of such obligations. At December 31, 2020, the total amount of Guaranteed Debt was $30.59 billion, which was comprised of $27.5 billion of EPO's senior notes, $2.63 billion of EPO's junior subordinated notes and $455.6 million of related accrued interest.

The Partnership's guarantees of EPO's senior note obligations, commercial paper notes and borrowings under bank credit facilities represent unsecured and unsubordinated obligations of the Partnership that rank equal in right of payment to all other existing or future unsecured and unsubordinated indebtedness of the Partnership. In addition, these guarantees effectively rank junior in right of payment to any existing or future indebtedness of the Partnership that is secured and unsubordinated, to the extent of the assets securing such indebtedness.

The Partnership's guarantees of EPO's junior subordinated notes represent unsecured and subordinated obligations of the Partnership that rank equal in right of payment to all other existing or future subordinated indebtedness of the Partnership and senior in right of payment to all existing or future equity securities of the Partnership. The Partnership's guarantees of EPO's junior subordinated notes effectively rank junior in right of payment to (i) any existing or future indebtedness of the Partnership that is secured, to the extent of the assets securing such indebtedness and (ii) all other existing or future unsecured and unsubordinated indebtedness of the Partnership.

The Partnership may be released from its guarantee obligations only in connection with EPO's exercise of its legal or covenant defeasance options as described in the underlying agreements.

<u>Selected Financial Information of Obligor Group</u>
The following tables present summarized financial information of the Partnership (as Parent Guarantor) and EPO (as Subsidiary Issuer) on a combined basis (collectively, the "Obligor Group"), after the elimination of intercompany balances and transactions among the Obligor Group.

In accordance with Rule 13.01 of Regulation S-X, the summarized financial information of the Obligor Group excludes the Obligor Group's equity in income and investments in the consolidated subsidiaries of EPO that are not party to the guarantee obligations (the "Non-Obligor Subsidiaries"). The total carrying value of the Obligor Group's investments in the Non-Obligor Subsidiaries was $45.98 billion at December 31, 2020. The Obligor Group's equity in the earnings of the Non-Obligor Subsidiaries for the year ended December 31, 2020 was $3.54 billion. Although the net assets and earnings of the Non-Obligor Subsidiaries are not directly available to the holders of the Guaranteed Debt to satisfy the repayment of such obligations, there are no significant restrictions on the ability of the Non-Obligor Subsidiaries to pay distributions or make loans to EPO or the Partnership. EPO exercises control over the Non-Obligor Subsidiaries. We continue to believe that the consolidated financial statements of the Partnership presented under Item 8 of this annual report provide a more appropriate view of our credit standing. Our investment grade credit ratings are based on the Partnership's consolidated financial statements and not the Obligor Group financial information presented below.

The following table presents summarized balance sheet information for the combined Obligor Group at December 31, 2020 (dollars in millions):

Selected asset information:		
Current receivables from Non-Obligor Subsidiaries	$	775.4
Other current assets		5,805.7
Long-term receivables from Non-Obligor Subsidiaries		187.3
Other noncurrent assets, excluding investments in Non-Obligor Subsidiaries of $45.98 billion		8,198.5
Selected liability information:		
Current portion of Guaranteed Debt, including interest of $455.6 million	$	1,780.6
Current payables to Non-Obligor Subsidiaries		1,129.0
Other current liabilities		3,858.6
Noncurrent portion of Guaranteed Debt, principal only		28,806.8
Noncurrent payables to Non-Obligor Subsidiaries		27.0
Other noncurrent liabilities		42.9
Mezzanine equity of Obligor Group:		
Preferred units	$	49.3

The following table presents summarized income statement information for the combined Obligor Group for the year ended December 31, 2020 (dollars in millions):

Revenues from Non-Obligor Subsidiaries	$	2,602.4
Revenues from other sources		15,361.4
Operating income of Obligor Group		1,069.7
Net loss of Obligor Group excluding equity in earnings of Non-Obligor Subsidiaries of $3.54 billion		(157.0)

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2020 (dollars in millions):

		Payment or Settlement due by Period			
Contractual Obligations	**Total**	**In less than 1 year**	**In 1-3 years**	**In 4-5 years**	**More than 5 years**
Scheduled maturities of debt obligations (1)	$ 30,146.4	$ 1,325.0	$ 2,650.0	$ 2,000.0	$ 24,171.4
Estimated cash payments for interest (2)	28,834.6	1,294.0	2,442.2	2,284.2	22,814.2
Operating lease obligations (3)	460.5	33.7	69.3	58.7	298.8
Purchase obligations:					
Product purchase commitments (4)	14,800.7	2,266.6	4,230.6	3,501.4	4,802.1
Service payment commitments (4,5)	278.8	62.0	102.0	29.0	85.8
Other long-term liabilities (6)	365.8	–	85.8	50.8	229.2
Total contractual payment obligations	$ 74,886.8	$ 4,981.3	$ 9,579.9	$ 7,924.1	$ 52,401.5

(1) Represents scheduled future maturities of our current and long-term debt principal obligations. For information regarding our consolidated debt obligations, see Note 7 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

(2) Estimated cash payments for interest are based on the principal amount of our consolidated debt obligations outstanding at December 31, 2020, the contractually scheduled maturities of such balances, and the applicable interest rates. Our estimated cash payments for interest are influenced by the long-term maturities of our $2.65 billion in junior subordinated notes (due June 2067 through February 2078). The estimated cash payments assume that (i) the junior subordinated notes are not repaid prior to their respective maturity dates and (ii) the amount of interest paid on the junior subordinated notes is based on either (a) the current fixed interest rate charged or (b) the weighted-average variable rate paid in 2020, as applicable, for each note through the respective maturity date.

(3) Primarily represents (i) land held pursuant to property leases, (ii) the lease of underground storage caverns for natural gas and NGLs, (iii) the lease of transportation equipment used in our operations and (iv) office space leased from affiliates of EPCO.

(4) Represents enforceable and legally binding agreements to purchase goods or services as of December 31, 2020. The estimated payment obligations are based on contractual prices in effect at December 31, 2020 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.

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

(6) Primarily represents the noncurrent portion of asset retirement obligations and deferred revenues.

We are obligated to spend up to an aggregate $270 million over a ten-year period ending in 2025 on specified midstream gathering assets for certain producers utilizing our EFS Midstream System. If constructed, these new assets would be owned by us and be a component of the EFS Midstream System. As of December 31, 2020, we have spent $151 million of the $270 million commitment. Due to the uncertain timing of the remaining potential capital expenditures, we have excluded this amount from the preceding table.

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

Off-Balance Sheet Arrangements

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

Related Party Transactions

For information regarding our related party transactions, see Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report as well as Part III, Item 13 of this annual report.

Insurance

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

General

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with assets, liabilities and certain anticipated future transactions, we use derivative instruments such as futures, forward contracts, swaps and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

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

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

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

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

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, petrochemicals and refined products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps and basis swaps.

The following table summarizes our portfolio of commodity derivative instruments outstanding at December 31, 2020 (volume measures as noted):

	Volume (1)		Accounting
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (billion cubic feet ("Bcf"))	6.0	n/a	Cash flow hedge
Forecasted sales of NGLs (million barrels ("MMBbls")) (3)	0.6	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities (Bcf)	4.0	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	142.8	1.6	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	172.1	4.5	Cash flow hedge
NGLs inventory management activities (MMBbls)	1.9	n/a	Fair value hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	41.2	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	51.1	3.3	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.8	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	32.9	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	44.5	n/a	Cash flow hedge
Petrochemical marketing:			
Forecasted purchases of petrochemical products (MMBbls)	0.4	n/a	Cash flow hedge
Forecasted sales of petrochemical products (MMBbls)	0.5	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3)	10.3	0.4	Mark-to-market
NGL risk management activities (MMBbls) (3)	26.5	7.9	Mark-to-market
Refined products risk management activities (MMBbls) (3)	6.9	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (3)	32.5	2.6	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is December 2022, December 2021 and October 2023, respectively.
(3) Reflects the use of derivative instruments to manage risks associated with our transportation, processing and storage assets.

At December 31, 2020, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging the fair value of commodity products held in inventory and (iii) hedging natural gas processing margins.

The following tables show the effect of hypothetical price movements on the estimated fair values of our principal commodity derivative instrument portfolios at the dates indicated (dollars in millions).

The fair value information presented in the sensitivity analysis tables excludes the impact of applying Chicago Mercantile Exchange ("CME") Rule 814, which deems that financial instruments cleared by the CME are settled daily in connection with variation margin payments. As a result of this exchange rule, CME-related derivatives are considered to have no fair value at the balance sheet date for financial reporting purposes; however, the derivatives remain outstanding and subject to future commodity price fluctuations until they are settled in accordance with their contractual terms. Derivative transactions cleared on exchanges other than the CME (e.g., the Intercontinental Exchange or ICE) continue to be reported on a gross basis.

Natural gas marketing portfolio

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2019**	**December 31, 2020**	**January 29, 2021**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ 1.1	$ 3.7	$ 3.3
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(4.3)	2.6	2.6
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	6.6	4.9	4.1

NGL and refined products marketing, natural gas processing and octane enhancement portfolio

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2019**	**December 31, 2020**	**January 29, 2021**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ 43.7	$ (388.2)	$ (286.9)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(19.0)	(521.0)	(359.6)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	106.4	(255.4)	(214.1)

The increase in fair value of our NGL and refined products marketing, natural gas processing and octane enhancement hedging portfolio from December 31, 2020 to January 29, 2021 is primarily due to the settlement of NGL and refined products positions in January 2021, partially offset by an increase in the underlying commodity prices of unsettled refined product positions.

Crude oil marketing portfolio

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2019**	**December 31, 2020**	**January 29, 2021**
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ (9.6)	$ (184.3)	$ (225.3)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(50.6)	(266.5)	(315.0)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	31.5	(102.1)	(135.7)

The decrease in fair value of our crude oil hedging portfolio from December 31, 2020 to January 29, 2021 is primarily due to an increase in the underlying crude oil prices of unsettled positions.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward-starting swaps, options to enter into forward-starting swaps ("swaptions"), and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy may be used in controlling our overall cost of capital associated with such borrowings.

Sensitivity Analysis

At December 31, 2020, our interest rate hedging portfolio consisted of forward-starting swaps. Forward-starting swaps hedge the risk of an increase in underlying benchmark interest rates during the period of time between the inception date of the swap agreement and the future date of a debt issuance. Under the terms of the forward-starting swaps, we pay to the counterparties (at the expected settlement dates of the instruments) amounts based on a fixed interest rate applied to a notional amount and receive from the counterparties an amount equal to a variable interest rate (based on LIBOR or an equivalent index rate) on the same notional amount.

With respect to the tabular data below, the portfolio's estimated economic value at a given date is based on a number of factors, including the number and types of derivatives outstanding at that date, the notional value of the swaps and associated interest rates. The following table summarizes our portfolio of forward-starting swaps at December 31, 2020 (dollars in millions):

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Expected Settlement Date	Weighted-Average Fixed Rate Locked	Accounting Treatment
Future long-term debt offering	1 forward-starting swap	$75.0	4/2021	2.41%	Cash flow hedge
Future long-term debt offering	5 forward-starting swaps	$500.0	4/2021	2.13%	Cash flow hedge
Future long-term debt offering	2 forward-starting swaps (1)	$150.0	2/2022	1.72%	Cash flow hedge
Future long-term debt offering	1 forward starting swap (1)	$100.0	4/2021	1.46%	Cash flow hedge
Future long-term debt offering	2 forward starting swaps (1)	$150.0	2/2022	1.48%	Cash flow hedge
Future long-term debt offering	2 forward starting swaps (1)	$100.0	2/2022	0.95%	Cash flow hedge

(1) These swaps were entered into during the first quarter of 2020.

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

		Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2019	December 31, 2020	January 29, 2021
Fair value assuming no change in underlying interest rates	*Asset (Liability)*	$ (13.5)	$ (107.7)	$ (48.3)
Fair value assuming 10% increase in underlying interest rates	*Asset (Liability)*	38.2	(69.4)	(6.8)
Fair value assuming 10% decrease in underlying interest rates	*Asset (Liability)*	(68.3)	(147.6)	(91.8)

The increase in fair value of our interest rate hedging portfolio from December 31, 2020 to January 29, 2021 was primarily due to an increase in market interest rates relative to the fixed rates specified in the swap agreements.

<u>LIBOR phase-out</u>
The variable rates referenced in interest rate swap agreements often reference the London Interbank Offered Rate ("LIBOR"). In July 2017, the Financial Conduct Authority in the U.K. announced a desire to phase out LIBOR as a benchmark by the end of June 2023. Financial industry working groups are developing replacement rates and methodologies to transition existing agreements that depend on LIBOR as a reference rate. We currently do not expect the transition from LIBOR to have a material impact on us.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

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

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

Disclosure Controls and Procedures

As of the end of the period covered by this annual report, our management carried out an evaluation, with the participation of (i) A. James Teague, Co-Chief Executive Officer of Enterprise GP and (ii) W. Randall Fowler, Co-Chief Executive Officer and Chief Financial Officer of Enterprise GP, of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Mr. Teague and Mr. Fowler are our co-principal executive officers and Mr. Fowler is also our principal financial officer. Based on this evaluation, as of the end of the period covered by this annual report, Messrs. Teague and Fowler concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our principal executive and financial officers, as appropriate to allow for timely decisions regarding required disclosures; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fourth quarter of 2020, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The containment measures enacted by local, state and national governmental authorities in response to COVID-19 have had minimal impact on our internal controls over financial reporting to date. As a result of prior emergency planning efforts, we have effective processes in place to ensure the continuity of our operations, including our accounting, risk control and information technology functions.

Section 302 and 906 Certifications

The required certifications of Messrs. Teague and Fowler under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 are included as exhibits to this annual report (see Exhibits 31 and 32 under Part IV, Item 15 of this annual report).

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2020

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries, including its Co-Chief Executive Officer and its Co-Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control system was designed to provide reasonable assurance to the management of Enterprise Products Partners L.P. and the Board of Directors of its general partner regarding the preparation and fair presentation of Enterprise Products Partners L.P.'s published financial statements.

Our management assessed the effectiveness of Enterprise Products Partners L.P.'s internal control over financial reporting as of December 31, 2020. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control—Integrated Framework (2013)*. This assessment included a review of the design and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on our assessment, we believe that, as of December 31, 2020, Enterprise Products Partners L.P.'s internal control over financial reporting is effective based on those criteria.

Our Audit and Conflicts Committee is comprised of independent directors who are not officers or employees of our general partner. This committee meets regularly with members of management, internal audit staff and representatives of Deloitte & Touche LLP, which is our independent registered public accounting firm, to discuss the adequacy of Enterprise Products Partners L.P.'s internal controls over financial reporting, consolidated financial statements and the nature, extent and results of the audit effort. Management reviews all of Enterprise Products Partners L.P.'s significant accounting policies and assumptions that affect its results of operations with the Audit and Conflicts Committee. Both the independent registered public accounting firm and our internal auditors have direct access to the Audit and Conflicts Committee without the presence of management.

Deloitte & Touche LLP has issued its attestation report regarding our internal control over financial reporting. See "Report of Independent Registered Public Accounting Firm" included within this Part II, Item 9A.

Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this annual report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in their respective capacities indicated below on March 1, 2021.

/s/ A. James Teague	/s/ W. Randall Fowler
Name: A. James Teague	Name: W. Randall Fowler
Title: Co-Chief Executive Officer of Enterprise Products Holdings LLC	Title: Co-Chief Executive Officer and Chief Financial Officer of Enterprise Products Holdings LLC

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products Holdings LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2020, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements as of and for the year ended December 31, 2020, of the Company and our report dated March 1, 2021, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting* as of December 31, 2020. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 1, 2021

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND PARTNERSHIP GOVERNANCE.

Partnership Management

The following individuals currently serve as members of the Board of Directors (the "Board") of Enterprise GP: Richard H. Bachmann, Carin M. Barth, Murray E. Brasseux, W. Randall Fowler, James T. Hackett, William C. Montgomery, John R. Rutherford, Richard S. Snell, A. James Teague, Harry P. Weitzel and Randa Duncan Williams. Ms. Duncan Williams serves as the non-executive Chairman of the Board, and Mr. Bachmann serves as the non-executive Vice Chairman of the Board.

Larry J. Casey and Edwin C. Smith serve as advisory directors for Enterprise GP, and O.S. Andras serves as an honorary director. Dr. Ralph S. Cunningham also served as an advisory director until his passing in November 2020. Service as an advisory or honorary director does not confer any of the rights, obligations, liabilities or responsibilities of a director of Enterprise GP (including any power or authority to vote on any matters as a director).

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for our management, administrative or operating functions. Pursuant to the ASA with EPCO, these roles are performed by employees of EPCO, which are under the direction of the Board and executive officers of Enterprise GP. The executive officers of Enterprise GP are elected for one-year terms and may be removed, with or without cause, only by the Board. Our limited partners do not elect the officers or directors of Enterprise GP. The DD LLC Trustees, through their control of Enterprise GP, have the ability to elect, remove and replace at any time, the officers and directors of Enterprise GP. Each member of the Board of Enterprise GP serves until such member's death, resignation or removal. The employees of EPCO who served as directors of Enterprise GP during 2020 were Ms. Duncan Williams and Messrs. Bachmann, Fowler, Teague and Weitzel.

Notwithstanding any contractual limitation on its obligations or duties, Enterprise GP is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to Enterprise GP. Whenever possible, Enterprise GP intends to make any such indebtedness or other obligations non-recourse to itself.

Under our partnership agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events, any person who is or was serving as a director, officer, employee, agent, fiduciary or trustee of the Partnership, Enterprise GP or any of their respective affiliates.

Office of the Chairman

The Office of the Chairman is a management oversight group comprised of four individuals: Ms. Duncan Williams (as Chairman of the Board), Mr. Bachmann (as Vice Chairman of the Board), Mr. Teague (as Co-Chief Executive Officer ("Co-CEO")) and Mr. Fowler (as Co-CEO and Chief Financial Officer ("CFO")). The purpose of the Office of the Chairman is for the group to serve collectively as a liaison between the Board and senior management with respect to, and to provide the Chairman, Vice-Chairman, Co-CEOs, and CFO a venue to discuss, certain matters including:

- our strategic direction (including business opportunities through organic growth and acquisitions);
- the vision, leadership and development of our management team;
- our business goals and operational performance; and
- strategies to preserve our financial strength.

In addition, the Office of the Chairman assists the Board and its Governance Committee in identifying director education opportunities and in determining the size and composition of the Board and recruitment of new members. The Office of the Chairman also oversees policies that (i) reflect our values and business goals and (ii) enhance the effectiveness of our governance structure. The Office of the Chairman also collectively oversees and provides strategic direction for our legal and human resources departments.

In her role as Chairman of the Board (a non-executive role), Ms. Duncan Williams is responsible for, among other things: (i) presiding over and setting the agendas for meetings of the Board, with due consideration of our values and business goals and an effective governance structure; (ii) overseeing the appropriate flow of information to the Board; (iii) acting as a liaison between the Board and senior management; and (iv) meeting regularly with the Board to review our strategic direction.

In his role as Vice Chairman of the Board (a non-executive role), Mr. Bachmann is responsible for, among other things: (i) assisting the Chairman of the Board in the execution of the Chairman of the Board's functions and responsibilities, as requested from time to time by the Chairman of the Board; and (ii) meeting regularly with the Board to review our strategic direction.

In his role as Co-CEO, Mr. Teague is our co-principal executive officer and is responsible for, among other things: (i) managing our overall business and financial strategy and day-to-day operations; (ii) a principal focus area of overseeing and providing strategic direction for us, subject to Board approval, in the areas of operations, commercial activities, business development, and health and safety; and (iii) providing the required certifications as co-principal executive officer of Enterprise GP (together with Mr. Fowler) in connection with our disclosure controls and procedures and internal control over financial reporting.

In his role as Co-CEO and CFO, Mr. Fowler is our co-principal executive officer and our principal financial officer and is responsible for, among other things: (i) managing our overall business and financial strategy; (ii) a principal focus are of overseeing and providing strategic direction for us, subject to Board approval, in the areas of accounting, risk management, finance, treasury and cash management, information technology, investor relations, and public relations and (iii) providing the required certifications as both (a) a co-principal executive officer of Enterprise GP (together with Mr. Teague) and (b) the principal financial officer of Enterprise GP in connection with our disclosure controls and procedures and internal control over financial reporting.

Directors and Executive Officers of Enterprise GP

The following table sets forth the name, age and position of each of the directors, excluding advisory or honorary directors, and executive officers of Enterprise GP at March 1, 2021. Each executive officer holds the same respective office shown below in the managing member of EPO.

Name	Age	Position with Enterprise GP
Randa Duncan Williams (1,2,6)	59	Director and Chairman of the Board
Richard H. Bachmann (1,6)	68	Director and Vice Chairman of the Board
A. James Teague (1,6,7,8)	75	Director and Co-CEO
W. Randall Fowler (1,6,7,8)	64	Director, Co-CEO and CFO
Carin M. Barth (2,6)	58	Director
Murray E. Brasseux (4)	72	Director
James T. Hackett (2,3,6)	67	Director
William C. Montgomery (4,5)	59	Director
John R. Rutherford (4)	60	Director
Richard S. Snell (4,6)	78	Director
Harry P. Weitzel (6,8)	56	Director and Executive Vice President, General Counsel and Secretary
Graham W. Bacon (8)	57	Executive Vice President and Chief Operating Officer
R. Daniel Boss (8)	45	Executive Vice President – Accounting, Risk Control and Information Technology
Christian M. Nelly (8)	45	Executive Vice President – Finance and Sustainability and Treasurer
Brent B. Secrest (8)	48	Executive Vice President and Chief Commercial Officer
Michael W. Hanson (8)	53	Vice President and Principal Accounting Officer

(1) Member of Office of the Chairman
(2) Member of the Governance Committee
(3) Chairman of the Governance Committee
(4) Member of the Audit and Conflicts Committee
(5) Chairman of the Audit and Conflicts Committee
(6) Member of the Capital Projects Committee
(7) Co-Chairman of the Capital Projects Committee
(8) Executive officer

The following information presents a brief description of the business experience of our directors and executive officers:

Randa Duncan Williams

Ms. Duncan Williams was elected Chairman of the Board of Enterprise GP in February 2013 and a director of Enterprise GP in November 2010. She was elected Chairman of EPCO in May 2010, having previously served as Group Co-Chairman since 1994. Ms. Duncan Williams has served as a member of Enterprise GP's Governance Committee since April 2014 and Capital Projects Committee since November 2016.

Ms. Duncan Williams has served as a director of EPCO since February 1991. She also served as a director of the general partner of Enterprise GP Holdings L.P. ("Holdings GP") from May 2007 to November 2010.

Prior to joining EPCO in 1994, Ms. Duncan Williams practiced law with the firms Butler & Binion and Brown, Sims, Wise & White. Ms. Duncan Williams previously served on the board of directors of Encore Bancshares from July 2007 until July 2012. She currently serves on the board of trustees for numerous charitable organizations. Ms. Duncan Williams is the daughter of the late Mr. Dan L Duncan, our founder.

Richard H. Bachmann

Mr. Bachmann was elected a director and Vice Chairman of the Board of Enterprise GP in January 2016 and has served as a member of its Capital Projects Committee since November 2016. He previously served as a director of Enterprise GP from November 2010 through April 2014.

Mr. Bachmann was elected President and Chief Executive Officer ("CEO") of EPCO in May 2010 and has served as a director since January 1999. He previously served as Secretary of EPCO from May 1999 to May 2010 and as a Group Vice Chairman of EPCO from December 2007 to May 2010. Mr. Bachmann served as an Executive Vice President of Holdings GP from April 2005 to November 2010 and as a director of Holdings GP from February 2006 to November 2010. He served as Chief Legal Officer and Secretary of Holdings GP from April 2005 to May 2010. Mr. Bachmann served as Executive Vice President and Chief Legal Officer of Enterprise Products GP, LLC ("EPGP," our former general partner) from February 1999 until November 2010 and as Secretary of EPGP from November 1999 to November 2010. He previously served as a director of EPGP from June 2000 to January 2004 and from February 2006 to May 2010. Mr. Bachmann served as a director of DEP Holdings, LLC ("DEP GP"), the general partner of Duncan Energy Partners L.P., from October 2006 to May 2010 and as President and CEO of DEP GP from October 2006 to April 2010.

A. James Teague

Mr. Teague was elected Co-CEO of Enterprise GP in January 2020 and has been a director of Enterprise GP since November 2010. Mr. Teague previously served as CEO of Enterprise GP from January 2016 to January 2020, as the Chief Operating Officer ("COO") of Enterprise GP from November 2010 to December 2015 and served as an Executive Vice President of Enterprise GP from November 2010 until February 2013. He has served as Co-Chairman of the Capital Projects Committee of Enterprise GP since November 2016.

Mr. Teague served as an Executive Vice President of EPGP from November 1999 to November 2010 and additionally as a director from July 2008 to November 2010 and as COO from September 2010 to November 2010. In addition, he served as Chief Commercial Officer of EPGP from July 2008 until October 2010. He served as Executive Vice President and Chief Commercial Officer of DEP GP from July 2008 until September 2011. He previously served as a director of DEP GP from July 2008 to May 2010 and as a director of Holdings GP from October 2009 to May 2010.

Mr. Teague joined us in connection with our purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. From 1998 to 1999, Mr. Teague served as President of Tejas Natural Gas Liquids, LLC, then an affiliate of Shell. From 1997 to 1998, he was President of Marketing and Trading for MAPCO, Inc. Mr. Teague also serves on the board of directors of Solaris Oilfield Infrastructure, Inc.

W. Randall Fowler

Mr. Fowler was elected a director of Enterprise GP in September 2011 and has served as its Co-CEO since January 2020, having previously served as President from January 2016 to January 2020 and as Chief Administrative Officer from April 2015 to January 2016. Mr. Fowler has served as CFO of Enterprise GP since August 2018, having previously served as Executive Vice President and CFO of Enterprise GP from November 2010 to March 2015 and as Executive Vice President and CFO of EPGP from August 2007 to November 2010. He has served as Co-Chairman of the Capital Projects Committee of Enterprise GP since November 2016.

Mr. Fowler was elected Vice Chairman and CFO of EPCO in May 2010. He previously served as President and CEO of EPCO from December 2007 to May 2010 and as its CFO from April 2005 to December 2007.

Mr. Fowler also served as President and CEO of DEP GP from April 2010 until September 2011 and as Executive Vice President and CFO of DEP GP from August 2007 to April 2010. He served as a director of DEP GP from September 2006 until September 2011. Mr. Fowler served as Senior Vice President and Treasurer of EPGP from February 2005 to August 2007 and of DEP GP from October 2006 to August 2007. Mr. Fowler also previously served as a director of EPGP and of Holdings GP from February 2006 to May 2010. Mr. Fowler also served as Senior Vice President and CFO of Holdings GP from August 2005 to August 2007.

Mr. Fowler, a Certified Public Accountant (inactive), joined us as Director of Investor Relations in January 1999. He also serves as Chairman of the Board of the Energy Infrastructure Council (formerly the Master Limited Partnership Association). Mr. Fowler is on the Advisory Board of Alerian, an independent provider of market intelligence for master limited partnerships ("MLPs"), which includes its benchmark Alerian MLP Index, or AMZ. He also serves on the Advisory Board for the College of Business at Louisiana Tech University.

Carin M. Barth

Ms. Barth was elected a director of Enterprise GP in October 2015. She has served as a member of its Governance Committee since October 2015 and its Capital Projects Committee since November 2016.

Ms. Barth is co-founder and President of LB Capital Inc., a private equity investment firm established in 1988. She currently serves on the following boards of directors: Black Stone Minerals, L.P., where she is Chair of the Audit Committee, Group 1 Automotive, Inc., where she is Chair of the Audit Committee and BBVA USA Bancshares, Inc., a subsidiary of BBVA Group, where she is Chair of the Audit and Compliance Committee. Additionally, she is Chairman of The Welch Foundation and a board member of the Ronald McDonald House of Houston.

Ms. Barth previously served on the Housing Commission at the Bi-Partisan Policy Center in Washington, DC from 2011 to 2014, and was a Commissioner of the Texas Department of Public Safety from 2008 to 2014. She also served as a board member of the following: Bill Barrett Corporation from June 2012 to May 2016; Halcon Resources Corporation from April 2019 to October 2019; Western Refining Inc., where she was Chair of the Audit Committee from March 2006 to January 2016; Methodist Hospital Research Institute from 2007 to 2012; Encore Bancshares, Inc. from 2009 to 2012; Amegy Bancorporation, Inc. from 2006 to 2009; the Texas Public Finance Authority from 2006 to 2008; and the Texas Tech University System Board of Regents from 1999 to 2005. She was appointed by President George W. Bush to serve as CFO of the U.S. Department of Housing and Urban Development from 2004 to 2005.

Murray E. Brasseux

Mr. Brasseux was elected a director of Enterprise GP and a member of its Audit and Conflicts Committee in January 2019.

Mr. Brasseux is also a member of the board of directors of Adams Resources & Energy, Inc., a publicly-traded company primarily engaged in the business of crude oil marketing and tank truck transportation of liquid and dry bulk chemicals. Mr. Brasseux retired from Compass Bank in December 2014 after 20 years of service, having most recently served as Managing Director of Oil & Gas Finance. Mr. Brasseux also served as a consultant to Compass Bank from January 2015 to June 2015 and as a consultant to Loughlin Management Partners (a restructuring and advisory firm) from June 2015 to December 2017. Mr. Brasseux also serves on the board of the Rare Book School (an affiliate of the University of Virginia).

James T. Hackett

Mr. Hackett was elected a director of Enterprise GP in April 2014. He has served as a member of its Governance Committee since April 2014, including in the role of committee Chairman since November 2016. In addition, Mr. Hackett has served as a member of Enterprise GP's Capital Projects Committee since November 2016.

Mr. Hackett served as Executive Chairman of Alta Mesa Resources, Inc. (formerly named Silver Run Acquisition Corporation II) ("Alta Mesa") until March 2020. In September 2019, Alta Mesa and certain of its affiliates filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code ("Chapter 11"). In January 2020, Kingfisher Midstream, LLC, an affiliate of Alta Mesa engaged in providing certain midstream energy services, including crude oil and gas gathering, processing and marketing to producers of natural gas, natural gas liquids, crude oil and condensate (where Mr. Hackett previously served as CEO and President), filed a voluntary petition for reorganization under Chapter 11.

Mr. Hackett previously served as an Advisor and Partner to private energy investing firm Riverstone Holdings LLC. He served as Executive Chairman of the board of directors of Anadarko Petroleum Corporation ("Anadarko"), an independent oil and natural gas exploration and production company, from 2012 to 2013 after serving as its CEO from 2003 to 2012 and Chairman of the Board from 2006 to 2012. He also served as Anadarko's President from 2003 to 2010. Mr. Hackett is a board member of Fluor Corporation and National Oilwell Varco, Inc.. He is a former director of Cameron International and the former Chairman of the Board of the Federal Reserve Bank of Dallas. He is a past Chairman (and now Member) of the National Petroleum Council, a member of the Society of Petroleum Engineers, a member of the Baylor College of Medicine Board of Trustees and a member of the Rice University Board of Trustees. Mr. Hackett also serves as a faculty member at Rice University and The University of Texas (Austin).

William C. Montgomery

Mr. Montgomery was elected a director of Enterprise GP and appointed a member of its Audit and Conflicts Committee in October 2015. Mr. Montgomery has served as Chairman of the Audit and Conflicts Committee since January 2020.

Mr. Montgomery has served as a Partner of Quantum Energy Partners since 2011 and is also a member of its Executive and Investment Committees. He is responsible for originating and overseeing investments in the oil and gas upstream and oilfield service sectors. Mr. Montgomery also serves on the board of Apache Corporation.

Prior to joining Quantum Energy Partners, Mr. Montgomery was a Partner in the Investment Banking Division of Goldman, Sachs & Co. where he headed the firm's Americas Natural Resources Group as well as its Houston office. His career as a banker spanned 22 years and was focused on large cap energy companies primarily in the upstream and oil service sectors. Mr. Montgomery has been an active civic leader, chairing the boards of The Houston Museum of Natural Science and The St. Francis Episcopal Day School and currently serves on the board of trustees of The Episcopal Health Foundation and the Board of Visitors of the MD Anderson Cancer Center.

John R. Rutherford

Mr. Rutherford was elected a director of Enterprise GP and appointed a member of its Audit and Conflicts Committee in January 2019.

Mr. Rutherford currently serves as a Senior Managing Director of NRI Energy Partners LLC, a firm that evaluates and invests in private and public energy companies and provides financial and strategic consulting services to energy companies and investment firms. He also serves as Senior Advisor to Energy Capital Partners, an energy investment firm focused on investing in the power, clean energy and midstream sectors. Mr. Rutherford previously served as Executive Vice President (Strategic Planning, M&A and Business Development) of the general partner of Plains All American Pipeline, L.P. ("Plains") and as a member of Plains' executive committee from October 2010 through July 2015. Mr. Rutherford also served as a financial consultant to Plains from July 2015 through September 2018. His career includes over 20 years of investment banking experience as a mergers and acquisitions and strategic advisor to public and private energy companies, investment firms, management teams and boards of directors. Prior to joining Plains, Mr. Rutherford served as Managing Director of the North American Energy Practice of Lazard Freres & Company from 2007 until 2010. Prior to joining Lazard, he was a partner at Simmons & Company for over ten years.

Richard S. Snell

Mr. Snell was elected a director of Enterprise GP and appointed a member of its Audit and Conflicts Committee in September 2011. He has served as a member of its Capital Projects Committee since November 2016.

Mr. Snell is a Certified Public Accountant and is of counsel with the law firm of Ytterberg Deery Knull LLP, having been with the firm since January 2017. He previously served as an attorney with the law firms of Thompson & Knight LLP (from 2000 to early 2017) and Snell & Smith, P.C. (from its founding in 1993 until 2000).

Mr. Snell served as a director of DEP GP from January 2010 to September 2011 and as a director of the general partner of TEPPCO Partners, L.P. from January 2006 until October 2009. From June 2000 until February 2006, he served as a director of EPGP.

Harry P. Weitzel

Mr. Weitzel was elected a director of Enterprise GP and appointed a member of its Capital Projects Committee in November 2016 and has served as Executive Vice President, General Counsel and Secretary of Enterprise GP since January 2020. He previously served as Senior Vice President, General Counsel and Secretary of Enterprise GP from April 2016 to January 2020 and as Senior Vice President, Deputy General Counsel and Secretary of Enterprise GP from January 2015 to April 2016. Mr. Weitzel is responsible for all our legal functions, including securities, litigation, employment, mergers and acquisitions, corporate governance and commercial transactions.

Mr. Weitzel has extensive experience as a commercial litigator, having practiced over 24 years in Texas and California. He has successfully represented individual, corporate and governmental clients as plaintiffs and defendants in a wide variety of business-related matters. Mr. Weitzel has tried cases in state and federal courts, as well as arbitrations under the American Arbitration Association, JAMS and the International Chamber of Commerce. He has handled appeals in state and federal courts. Prior to joining us, Mr. Weitzel was a commercial litigation partner with Pepper Hamilton LLP in Irvine, California from October 2009 to December 2014.

Graham W. Bacon

Mr. Bacon was elected Executive Vice President and Chief Operating Officer of Enterprise GP in September 2019. Mr. Bacon most recently served as Executive Vice President (Operations and Engineering) of Enterprise GP from October 2015 to August 2019 and continues to have responsibility for our operations and engineering teams in his new role. He previously served as Group Senior Vice President (Operations and Environmental, Health, Safety & Training) from February 2014 to October 2015; as Senior Vice President (Operations) from January 2012 to February 2014; as Vice President (Operations) from June 2006 to January 2012, and as Vice President (Engineering) from September 2005 to May 2006. He joined EPCO in 1991 and has held a variety of operations and engineering roles. Prior to joining EPCO, Mr. Bacon worked for Vista Chemical Company.

R. Daniel Boss

Mr. Boss, a Certified Public Accountant, was elected Executive Vice President – Accounting, Risk Control and Information Technology of Enterprise GP in January 2020 and previously served as Senior Vice President (Accounting and Risk Control) from August 2016 to January 2020. He is responsible for the overall leadership of our Accounting, Risk Control and Information Technology organizations. Mr. Boss served as a Senior Vice President of Enterprise GP from March 2015 to August 2016 with responsibility over our regulated business. He also served as Vice President (Risk Control) from April 2013 to March 2015 and as Senior Director (Risk Control) from January 2010 to March 2013. While serving in these positions, Mr. Boss was Chairman of the Risk Management Committee and had responsibilities for our marketing risk management policies, transaction controls and derivatives and hedging strategies compliance. Mr. Boss also served as Director (Volume Accounting) from November 2008 until January 2010 where he was responsible for gas marketing and commodity derivatives accounting, hedging and reporting. Prior to joining us, Mr. Boss held leadership positions with Merrill Lynch Commodities and Dynegy Inc.

Christian M. Nelly

Mr. Nelly was elected Executive Vice President – Finance and Sustainability and Treasurer of Enterprise GP in July 2020. He previously served as Executive Vice President – Finance and Treasurer from January 2020 to July 2020 and as Senior Vice President (Finance) and Treasurer from March 2019 to January 2020. Mr. Nelly is responsible for managing our financing activities, business planning and analysis, credit, cash management, corporate risk and insurance, investor relations, sustainability and public relations groups. Mr. Nelly served as Vice President and Treasurer from April 2015 to February 2019; Senior Director of Finance from April 2011 until March 2015; and Director of Finance from January 2008 to March 2011. Prior to joining us, Mr. Nelly spent 10 years with various corporate and investment banks where he executed transactions and maintained relationships with midstream and upstream energy companies and gained experience in strategic advisory, valuation, mergers and acquisitions, and capital raising.

Brent B. Secrest

Mr. Secrest was elected Executive Vice President and Chief Commercial Officer of Enterprise GP in September 2019. Mr. Secrest most recently served as Senior Vice President (Commercial) of Enterprise GP from July 2018 to August 2019. He previously served as Senior Vice President (Liquid Hydrocarbons Marketing) of Enterprise GP from May 2016 to June 2018, as Vice President (Crude Oil and Refined Products Marketing) from October 2015 to May 2016 and as Vice President (Crude Oil Pipelines and Terminals) from October 2012 to October 2015. He has also served us in various other leadership positions, including in the areas of NGL marketing and supply, commercial development, distribution, and business analysis. Mr. Secrest has over 20 years of experience in the energy industry and began his career at Basis Petroleum Inc. prior to joining EPCO in 1996.

Michael W. Hanson

Mr. Hanson was elected a Vice President of Enterprise GP in April 2011 and a Principal Accounting Officer in August 2016. His responsibilities include team leadership in financial and management reporting matters. Mr. Hanson reports to Mr. Boss. Mr. Hanson has served us and our affiliates in various accounting roles since 1992, including as an Assistant Controller from April 2007 to July 2016 and Director of Financial Reporting from November 2004 to March 2007.

Director Experience, Qualifications, Attributes and Skills

The following is a brief discussion of the experience, qualifications, attributes and skills that led us to the conclusion that each of the following persons should serve as a director of Enterprise GP.

Five of our directors are current employees of EPCO and officers of Enterprise GP or its affiliates. Each of these directors has significant experience in our industry as executive officers as well as other qualifications, attributes and skills. These include:

- for Ms. Duncan Williams, legal and community involvement with numerous charitable organizations, and active involvement in EPCO's businesses, including ownership in and management of our businesses;

- for Mr. Teague, over 40 years of commercial management of midstream assets and marketing and trading activities, both for third parties and for us;

- for Mr. Fowler, over 20 years of experience with our midstream assets, including finance, accounting and investor relations and, for over 15 years, as a member of our executive management team;

- for Mr. Bachmann, over 30 years of experience with our midstream assets, including legal, regulatory, contracts and mergers and acquisitions and, for over 20 years, as a member of either EPCO's or our executive management teams; and

- for Mr. Weitzel, over 25 years of experience in Texas and California as a commercial litigator, having successfully represented individual, corporate and governmental clients as plaintiffs and defendants in a wide variety of business-related matters.

Our six outside voting directors also have significant experience in a variety of capacities, as well as other qualifications, attributes and skills. These include:

- for Ms. Barth, executive management experience in various financial and governance roles;

- for Mr. Brasseux, executive management experience in banking and finance as well as governance roles;

- for Mr. Hackett, executive management of a major oil and gas exploration and production company;

- for Mr. Montgomery, executive management of both an investment banking firm and a private equity investment firm serving the global energy industry;

- for Mr. Rutherford, executive management experience in the midstream energy industry (including in the areas of strategic planning, mergers and acquisitions, investment banking and finance); and

- for Mr. Snell, professional experience involving complex legal and accounting matters.

As advisory directors, Mr. Casey has executive management experience in NGL and petrochemicals trading and related storage businesses, and Mr. Smith has experience in banking and investment matters. As an honorary director, Mr. Andras has a long history with us and our operations, including being a former CEO.

Partnership Governance

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals and maintain the trust and confidence of investors, employees, suppliers, business partners and other stakeholders.

A key element of strong governance is having independent members of the Board. Pursuant to the NYSE listing standards, a director will be considered independent if the Board determines that he or she does not have a material relationship with Enterprise GP or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with Enterprise GP or us). Based on the foregoing, the Board has affirmatively determined that Ms. Barth and Messrs. Brasseux, Hackett, Montgomery, Rutherford and Snell are independent directors under the NYSE rules.

Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, we are not required to comply with certain NYSE rules. In particular, we are not required to comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of Enterprise GP be comprised of a majority of independent directors. Currently, six of the eleven Board members of Enterprise GP are independent under NYSE rules; however, this composition may not always be in effect. Also, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of Enterprise GP maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Code of Conduct and Ethics and Corporate Governance Guidelines

Enterprise GP has adopted a Code of Conduct that applies to its directors, officers and employees. This code sets forth our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance on complying with the code, the reporting of compliance issues, and discipline for violations of the code. The Code of Conduct also establishes policies applicable to our Co-CEOs and CFO, and senior financial and other managers to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications, and prompt internal reporting of violations of the code (and thus accountability for adherence to the code). Employees are required to certify their understanding and compliance with the Code of Conduct on an annual basis. Training on the Code of Conduct is also provided to employees, where applicable.

Governance guidelines, together with applicable committee charters, provide the framework for effective governance of our partnership. The Board has adopted the *Governance Guidelines of Enterprise Products Partners* ("Governance Guidelines"), which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibilities of Board committees, the conduct and frequency of Board and committee meetings, management succession plans, director access to management and outside advisors, director compensation, director and executive officer equity ownership, director orientation and continuing education, and annual self-evaluation of the Board. The Board recognizes that effective governance is an on-going process, and thus, it will review the Governance Guidelines annually or more often as deemed necessary.

Audit and Conflicts Committee

The purpose of the Board's Audit and Conflicts Committee is to address audit and conflicts-related matters. In accordance with NYSE rules and the Securities Exchange Act of 1934, the Board has named four of its members to serve on the Audit and Conflicts Committee. Members of the Audit and Conflicts Committee must have a basic understanding of finance and accounting matters and be able to read and understand financial statements, and at least one member of the Audit and Conflicts Committee shall have accounting or related financial management expertise. The current members of the Audit and Conflicts Committee are Messrs. Brasseux, Montgomery, Rutherford and Snell, all of whom are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment. The Board has affirmatively determined that Mr. Montgomery satisfies the definition of "Audit Committee Financial Expert" as that term is defined in Item 407(d)(5) of Regulation S-K promulgated by the SEC.

The primary responsibilities of the Audit and Conflicts Committee include (i) reviewing potential conflicts of interest, including related party transactions, (ii) monitoring the integrity of our financial reporting process and related systems of internal control, (iii) ensuring our legal and regulatory compliance and that of Enterprise GP, (iv) overseeing the independence and performance of our independent public accountant, (v) approving all services performed by our independent public accountant, (vi) providing for an avenue of communication among the independent public accountant, management, internal audit function and the Board, (vii) encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels and (viii) reviewing areas of potential significant financial risk to our businesses.

If the Board believes that a particular matter presents a conflict of interest and proposes a resolution, the Audit and Conflicts Committee has the authority to review such matter to determine if the proposed resolution is fair and reasonable to us. Any matters approved by the Audit and Conflicts Committee are conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by Enterprise GP or the Board of any duties they may owe us or our unitholders.

Pursuant to its formal written charter, the Audit and Conflicts Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. The Audit and Conflicts Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Governance Committee

The primary purpose of the Governance Committee is to develop and recommend to the Board a set of governance guidelines applicable to our partnership, to review such guidelines from time to time and to oversee governance matters related to our business, including Board and Committee composition, qualifications of Board candidates, director independence, succession planning and related matters. The Governance Committee also assists in Board oversight of management's establishment and administration of our environmental, safety and transportation compliance policies, procedures, programs and initiatives, and related matters. In accordance with its charter, the Governance Committee shall be composed of not less than three members, at least a majority of whom shall be independent directors. Currently, the Governance Committee is comprised of Ms. Duncan Williams and two independent directors (Ms. Barth and Mr. Hackett).

Like the Audit and Conflicts Committee, the Governance Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. In addition, the Governance Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

A subcommittee of the Governance Committee, the Incentive Plan Administration Subcommittee, is involved in decision-making regarding employee compensation matters, including grants of equity-based awards. In accordance with the Governance Committee charter, this subcommittee shall be composed of two or more non-employee directors (currently, Ms. Barth and Mr. Hackett) and shall (i) review and approve all aspects of compensation of our Co-CEOs and CFO, (ii) administer the long-term incentive plans of the Partnership and its affiliates and (iii) review and approve all equity grants made to employees, consultants and/or directors as required by such long-term incentive plans. For more information regarding this subcommittee's role in executive compensation matters, see "Overview of Decision-Making Process regarding Compensation of Named Executive Officers" under Part III, Item 11 of this annual report.

Capital Projects Committee

The primary purpose of the Capital Projects Committee is to review and approve certain expenditures by Enterprise GP, the Partnership and/or their respective consolidated subsidiaries in connection with proposed capital projects. Currently, the Capital Projects Committee is comprised of Ms. Duncan Williams, Ms. Barth and Messrs. Bachmann, Fowler, Hackett, Snell, Teague and Weitzel. Messrs. Teague and Fowler are co-chairmen of the Capital Projects Committee.

Investor Access to Partnership Governance Information

We provide investors access to information relating to our governance procedures and principles, including the Code of Conduct, Governance Guidelines, the charters of the Audit and Conflicts Committee, the Governance Committee and the Capital Projects Committee, along with other information, through our website, www.enterpriseproducts.com. You may also contact our Investor Relations department at (866) 230-0745 for printed copies of these documents free of charge.

NYSE Corporate Governance Listing Standards

On March 10, 2020, Mr. Teague certified to the NYSE (as required by Section 303A.12(a) of the NYSE Listed Company Manual) that he was not aware of any violation by us of the NYSE's Corporate Governance listing standards as of that date.

Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the presiding director, who is responsible for leading and facilitating such executive sessions. Currently, the presiding director is Mr. Montgomery.

Confidential Telephone Hotline

In accordance with NYSE rules, we have established a toll-free, confidential telephone hotline (the "Hotline") so that interested parties may communicate with the presiding director or with all the non-management directors of Enterprise GP as a group. All calls to this Hotline are reported to the chairman of the Audit and Conflicts Committee, who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential Hotline is (844) 693-4318.

ITEM 11. EXECUTIVE COMPENSATION.

Executive Officer Compensation

We do not directly employ any of the persons responsible for managing our business. Instead, we are managed by Enterprise GP, the executive officers of which are employees of EPCO. Our management, administrative and operating functions are primarily performed by employees of EPCO in accordance with the ASA. Pursuant to the ASA, we reimburse EPCO for its compensation costs related to the employment of personnel working on our behalf. For information regarding the ASA, see Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Summary Compensation Table

The following table presents total compensation amounts paid, accrued or otherwise expensed by us with respect to our (i) co-CEOs, (ii) CFO and (iii) three highest paid officers of our general partner, other than our principal executive and financial officers, who were serving in such capacity at December 31, 2020. Collectively, these five individuals were our "named executive officers" for 2020. To the extent such individuals were also named executive officers for 2019 and 2018, their total compensation for those years is presented as well.

Name and Principal Position	Year	Cash Salary ($)	Bonus ($)	Equity-Based Awards ($) (1)	All Other Compensation ($) (2)	Total ($)
A. James Teague,	2020	$ 937,572	$ 3,000,000	$ 5,796,000	$ 915,797	$ 10,649,369
Co-CEO	2019	887,500	3,000,000	5,827,500	822,661	10,537,661
	2018	837,500	2,716,250	4,359,306	706,531	8,619,587
W. Randall Fowler,	2020	660,938	2,250,000	4,399,950	637,630	7,948,518
Co-CEO and CFO	2019	609,375	2,250,000	3,663,000	519,072	7,041,447
	2018	567,188	1,845,000	2,736,631	430,337	5,579,156
Graham W. Bacon,	2020	511,250	700,000	2,318,400	418,486	3,948,136
Executive Vice President and	2019	481,250	500,000	2,358,750	386,692	3,726,692
Chief Operating Officer	2018	418,750	411,000	3,159,310	315,136	4,304,196
Brent B. Secrest,	2020	468,750	700,000	2,356,199	315,031	3,839,980
Executive Vice President and	2019	390,000	500,000	1,248,750	219,012	2,357,762
Chief Commercial Officer	2018	332,500	359,750	2,007,334	168,921	2,868,505
Christian M. Nelly, Executive Vice President – Finance and Sustainability and Treasurer	2020	336,375	390,000	1,109,471	659,699	2,495,545

(1) Amounts represent our estimated share of the aggregate grant date fair value of equity-based awards granted during each year presented. See "Grants of Equity-Based Awards in Fiscal Year 2020" within this Item 11 for information regarding awards granted in the year ended December 31, 2020.

(2) Amounts include (i) contributions in connection with funded, qualified, defined contribution retirement plans, (ii) quarterly distributions paid on equity-based awards, (iii) the imputed value of life insurance premiums paid on behalf of the officer, (iv) employee retention payments and (v) other amounts.

Bonus amounts shown in the preceding table represent discretionary annual awards earned by each named executive officer with respect to the year presented. Bonus amounts for the years ended December 31, 2020 and 2019 were paid in cash in February 2021 and February 2020, respectively. For the year ended December 31, 2018, the dollar value of each officer's bonus (less applicable deductions and taxes) was remitted half in cash and half through the issuance of an equivalent value of newly issued Partnership common units, with both amounts provided to the employee in February 2019.

The following table presents the components of "All Other Compensation" for each named executive officer for the year ended December 31, 2020:

Named Executive Officer	Contributions Under Funded, Qualified, Defined Contribution Retirement Plans	Distributions Paid On Equity-Based Awards (1)	Life Insurance Premiums	Employee Retention Payments (2)	Other	Total All Other Compensation
A. James Teague	$ 34,200	$ 870,867	$ 5,438	$ –	$ 5,292	$ 915,797
W. Randall Fowler	25,650	603,898	3,267	–	4,815	637,630
Graham W. Bacon	34,200	376,020	2,838	–	5,428	418,486
Brent B. Secrest	31,350	276,960	990	–	5,731	315,031
Christian M. Nelly	30,566	135,416	965	487,500	5,252	659,699

(1) Reflects aggregate cash payments made to the named executive officer in connection with (i) distribution equivalent rights ("DERs") issued in tandem with phantom unit awards and (ii) distributions paid in connection with profits interest awards. With respect to DER amounts allocated to us, the following cash payments were made to the named executive officers during the year ended December 31, 2020: Mr. Teague, $862,677; Mr. Fowler, $575,539; Mr. Bacon, $350,660; Mr. Secrest, $243,916; and Mr. Nelly, $111,826.

(2) Amount presented for Mr. Nelly relates to a two-year employee retention agreement that settled in August 2020 and reflects the amount charged to us based on the percentage of time that Mr. Nelly spent on our business and affairs since the retention agreement was originally executed. For information regarding active employee retention agreements involving our named executive officers see "Compensation Discussion and Analysis" below.

Compensation Discussion and Analysis

<u>Elements of Compensation</u>

With respect to our named executive officers, compensation paid or awarded by us reflects only that portion of compensation paid by EPCO and allocated to us pursuant to the ASA, including an allocation of a portion of the cost of long-term incentive plans of EPCO. The elements of EPCO's compensation program, along with EPCO's other incentives (e.g., benefits, work environment and career development), are intended to provide a total rewards package to employees. The objective of EPCO's compensation program is to provide competitive compensation opportunities that will align and drive employee performance toward the creation of sustained long-term unitholder value. We believe that our compensation program allows us to attract, motivate and retain high quality talent with the skills and competencies that we require. Our compensation packages are designed to reward contributions by employees in support of the business strategies of EPCO and its affiliates at both our partnership and individual levels and to avoid risks that are likely to conflict with our risk management policies.

For the three years ended December 31, 2020, the primary elements of compensation for the named executive officers consisted of annual cash base salary, a discretionary annual bonus, equity awards under long-term incentive arrangements and other compensation, including very limited perquisites. With respect to the annual periods presented in the Summary Compensation Table, EPCO's compensation package for the named executive officers did not include any compensation elements based on targeted performance-based criteria. We believe that the absence of targeted performance-based criteria has the effect of discouraging excessive risk taking by our named executive officers.

Changes in the base salaries of our named executive officers during the three years ended December 31, 2020 were largely budget-driven and made consistent relative to increases in the base salaries of our other executive officers.

The bonus awards are discretionary and, in combination with annual base salaries, are intended to yield competitive total compensation levels for the named executive officers and drive performance in support of our business strategies. The annual bonus amount presented for each named executive officer reflects a general consideration of our overall financial and certain operating results for those periods. This general consideration takes into account a number of our financial measures, including cash flow from operating activities per unit, distributable cash flow per unit, gross operating margin, return on invested capital, and our 3-year and 5-year equity total return performance relative to peers. Operating results considered include certain safety performance and direct carbon dioxide equivalent ("CO2-e") emission measures. No weight or formula is given to any specific financial or operating performance measure. In addition, a subjective judgment of each named executive officer's performance for those periods is taken into account and reflected in the annual bonus amounts. The bonus amounts are also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers.

Each of our named executive officers has been granted equity-based compensation. The amount of equity-based compensation granted to our named executive officers reflects a general consideration of our overall financial and certain operating results described in the preceding paragraph, along with a subjective judgment of each named executive officer's contribution in support of that performance, without any weight or formula given to any specific financial or operating performance measure. The values of equity-based awards granted to the named executive officers are also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers. Each of the named executive officers received grants of phantom unit awards for the periods presented in the summary compensation table.

In addition, each of our named executive officers was granted a "profits interest" award in one or more of the Employee Partnerships, which serve as long-term incentive arrangements for key employees of EPCO. The names of the Employee Partnerships in which one or more of our named executive officers currently participate are: EPD PubCo Unit II L.P. ("PubCo II"); EPD PrivCo Unit I L.P. ("PrivCo I"); and EPD 2018 Unit IV L.P. ("EPD IV"). If certain conditions are met, the employee participants in each Employee Partnership will be entitled to (i) a residual profits interest in the assets of the Employee Partnership at liquidation, along with (ii) quarterly cash distributions.

In February 2020, the profits interest awards attributable to EPD PubCo Unit I L.P. ("PubCo I") vested and Messrs. Teague and Bacon received a liquidating distribution of residual partnership assets consisting of our common units. See "Vesting of Equity-Based Awards in 2020" within this Item 11 for additional information regarding these vestings. In September 2020, the partners of PubCo II and PrivCo I, which include certain of our named executive officers, amended their respective limited partnership agreements to provide for the vesting of their Class B limited partner interests on the earlier of (i) February 22, 2023, (ii) the first date on or after September 30, 2020 on which the closing market price of our common units is equal to or greater than $25.41 per unit, (iii) a change of control event, or (iv) dissolution of the applicable Employee Partnership. As a result of these modifications, the compensation for Messrs. Fowler, Secrest and Nelly attributable to equity-based awards for 2020 increased.

EPCO expects to continue its policy of paying for limited perquisites attributable to our named executive officers. EPCO also makes matching contributions under its defined contribution plans for the benefit of our named executive officers in the same manner as it does for other EPCO employees.

EPCO does not offer our named executive officers a defined benefit pension plan. Also, none of our named executive officers had nonqualified deferred compensation during the three years ended December 31, 2020.

In the second quarter of 2019, each of our named executive officers entered into a separate retention bonus agreement with EPCO. Pursuant to the retention bonus agreements, each such person will be entitled to a cash retention payment of $5 million (in the case of each of Messrs. Teague and Fowler), $1 million (in the case of each of Messrs. Bacon and Secrest) and $500,000 (in the case of Mr. Nelly), less all applicable withholding taxes and other required deductions on such payment (in each case, the applicable "Retention Payment"), in a lump sum within seven business days following his completion of continuous active fulltime employment with EPCO from April 15, 2019 through (i) May 31, 2022 (in the case of Mr. Teague) or (ii) May 31, 2023 (in the case of each of Messrs. Fowler, Bacon, Secrest and Nelly) (in each case, the applicable "Retention Period"), and provided that such person continues to perform his duties during the applicable Retention Period in a highly effective manner, as determined by the key executives of EPCO (the "Performance Requirement").

Notwithstanding the foregoing, in the event of an involuntary termination of any such person's employment prior to the end of his applicable Retention Period for specified reasons, including death, disability or termination of his employment by EPCO other than for "cause" (as defined in each retention bonus agreement), such person will receive (or in the event of his death, his designated beneficiary will receive), a cash payment equal to a pro-rata amount of his applicable Retention Payment, determined based on the number of days he is employed during the applicable Retention Period over the total number of days in such Retention Period (subject to meeting the Performance Requirement through his termination date). Any Retention Payment is in addition to any discretionary incentive compensation that EPCO or any of its affiliates may grant or have in place from time to time.

Overview of Decision-Making Process Regarding Compensation of Named Executive Officers
Prior to May 8, 2019, the Audit and Conflicts Committee of our general partner had review and approval authority with respect to the compensation of our Co-CEOs and CFO. In connection therewith, the Audit and Conflicts Committee had considered input and recommendations from the EPCO Trustees and the EPCO Human Resources department. Effective on May 8, 2019, a subcommittee of the Governance Committee of our general partner, the Incentive Plan Administration Subcommittee (the "IPA Subcommittee"), has, and, for the foreseeable future, will have, final and ultimate decision-making authority with respect to all aspects of compensation of our Co-CEOs and CFO. The current members of the IPA Subcommittee are Mr. Hackett and Ms. Barth, both of whom are "Non-Employee Directors" (as defined in SEC Rule 16b-3). It is anticipated that the IPA Subcommittee will, at its sole option and in its sole discretion, consider input and recommendations from the EPCO Trustees and EPCO's Human Resources department in making its compensation decisions for our Co-CEOs and CFO.

The compensation of our other named executive officers (other than equity-based awards granted under EPCO's long-term incentive plans) is determined by our Co-CEOs. Neither EPCO nor Enterprise GP has a separate compensation committee; however grants of equity-based compensation under EPCO's long-term incentive plans (e.g., phantom unit awards) to our named executive officers, including our Co-CEOs have been approved by the Audit and Conflicts Committee for grants prior to May 8, 2019, and have been, and for the foreseeable future, will be, approved by the IPA Subcommittee for grants on and after May 8, 2019.

The issuance of profits interest awards was approved by EPCO's Board of Directors.

The overall compensation for each named executive officer is not based on any formula or specific performance criteria; rather, the Audit and Conflicts Committee (prior to May 8, 2019), the IPA Subcommittee (on and after May 8, 2019), our Co-CEOs, and EPCO (as applicable) determine an appropriate level and mix of compensation for each officer on a case-by-case basis. Further, there is no established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation. However, some considerations that may be taken into account in making the case-by-case compensation determinations include the total value of all elements of compensation, the appropriate balance of internal pay equity among our executive officers, individual performance and potential, levels of responsibility and value to the organization. All compensation determinations are subjective and discretionary.

In making compensation decisions, EPCO considers market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, relevant compensation surveys and reports. These surveys and reports are conducted and prepared by third party compensation consultants. In 2019, EPCO engaged Meridian Compensation Partners, LLC (the "Consultant") to complete a detailed review of executive compensation relative to our industry. In connection with this review, the Consultant provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry participants. The market data for industry participants included information from CenterPoint Energy, Inc.; Dominion Energy, Inc.; Enbridge Inc.; Energy Transfer LP (formerly ETP); Kinder Morgan Inc.; Magellan Midstream Partners, L.P.; ONEOK, Inc.; Plains All American Pipeline, L.P.; Targa Resources Corporation; The Williams Companies, Inc.; and TC Energy Corporation (formerly TransCanada Corporation).

Neither we, nor EPCO, which engaged the Consultant, are aware of the specific data of the companies included in the Consultant's proprietary database for specific positions. EPCO uses the information provided in the Consultant's analysis to gauge whether compensation levels reported by the Consultant and the general ranges of compensation for EPCO employees in similar positions are comparable. However, that comparison is only a factor taken into consideration and may or may not impact compensation of our named executive officers. EPCO does not otherwise engage in benchmarking for the named executive officers' positions.

Allocation of Compensation Between Us and EPCO and its Other Affiliates
Under the ASA, the compensation costs of our named executive officers, including those costs related to equity-based awards, are allocated between us and other affiliates of EPCO based on the estimated amount of time that each officer spends on our consolidated businesses in any fiscal year. These percentages are reassessed at least quarterly.

With the exception of Messrs. Fowler and Nelly, each of our named executive officers devoted all of their time to our consolidated businesses during the years ended December 31, 2020, 2019 and 2018. Mr. Fowler devoted approximately 75% of his time to our consolidated businesses during this three year period, with the remainder of his time allocated to EPCO and its privately held affiliates. On average, Mr. Nelly devoted approximately 97.5% of his time to our consolidated businesses during 2020, with the remainder of his time allocated to EPCO and its privately held affiliates.

Grants of Equity-Based Awards in Fiscal Year 2020

The following table presents information concerning each grant of an equity-based award in 2020 to a named executive officer for which we will be allocated our pro rata share of the related cost under the ASA.

		Estimated Future Payouts Under Equity Incentive Plan Awards			
Award Type/Named Executive Officer	**Grant Date**	**Threshold (#)**	**Target (#)**	**Maximum (#)**	**Grant Date Fair Value of Equity-Based Awards ($)** (1)
Phantom unit awards: (2)					
A. James Teague	2/06/20	–	225,000	–	$ 5,796,000
W. Randall Fowler	2/06/20	–	225,000	–	4,347,000
Graham W. Bacon	2/06/20	–	90,000	–	2,318,400
Brent B. Secrest	2/06/20	–	90,000	–	2,318,400
Christian M. Nelly	2/06/20	–	43,000	–	1,079,988
Profits interest awards:					
W. Randall Fowler (3)	9/30/20	–	–	–	52,950
Brent B. Secrest (4)	9/30/20	–	–	–	37,799
Christian M. Nelly (4)	9/30/20	–	–	–	29,483

(1) Amounts presented reflect that portion of grant date fair value allocable to us based on the estimated percentage of time each named executive officer spent on our consolidated business activities during 2020. Based on current allocations, we estimate that the compensation expense we record for each named executive officer with respect to these awards will equal these amounts over time.
(2) The grant date fair value presented for the phantom unit awards is based, in part, on the closing price of our common units on February 6, 2020 of $25.76 per unit.
(3) Represents the incremental fair value of the modification of Mr. Fowler's profits interest award in PrivCo I, computed as of the amendment date of September 30, 2020.
(4) Represents the incremental fair value of the modification of Mr. Secrest's and Mr. Nelly's respective profits interest awards in PubCo II, computed as of the amendment date of September 30, 2020.

The fair value amounts presented in the preceding table are based on certain assumptions and considerations made by management. For information regarding these assumptions and considerations, see Note 13 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

The 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) (the "2008 Plan") provides for incentive awards to EPCO's key employees and non-employee directors and consultants who perform management, administrative or operational functions for us or our affiliates. Awards granted under the 2008 Plan may be in the form of phantom units, DERs, restricted common units, unit options, unit appreciation rights and other unit-based awards or substitute awards. For information regarding the number of common units authorized for issuance under the 2008 Plan, see "Securities Authorized for Issuance Under Equity Compensation Plans" under Part III, Item 12 of this annual report.

Phantom unit awards

Phantom unit awards allow recipients to acquire our common units (at no cost to the recipient apart from fulfilling service and other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. Phantom unit awards generally vest at a rate of 25% per year beginning one year after the grant date. Each phantom unit award includes a tandem DER, which entitles the holder to nonforfeitable cash payments equal to the product of the number of phantom unit awards outstanding for the participant and the cash distribution per common unit paid to our common unitholders.

Amendment of profits interest awards

On September 30, 2020, the partners of PrivCo I and PubCo II, including certain of our named executive officers, amended their respective limited partnership agreements to provide for the vesting of their Class B limited partner interests on the earlier of (i) February 22, 2023, (ii) the first date on or after September 30, 2020 on which the closing market price of our common units is equal to or greater than $25.41 per unit, (iii) a change of control event, or (iv) dissolution of the applicable Employee Partnership. As a result of these modifications, PubCo II and PrivCo I will recognize incremental compensation cost of $1.2 million and $0.5 million, respectively, through February 22, 2023. The preceding table reflects that portion of the total incremental compensation cost of the respective partnerships that are allocable to the named executive officers impacted by the changes.

Vesting of Equity-Based Awards in 2020

The following table presents the vesting of phantom unit awards to our named executive officers during the year ended December 31, 2020. These amounts are presented on a gross basis and do not reflect any allocation of compensation to affiliates under the ASA.

	Unit Awards	
Named Executive Officer	**Number of Units Acquired on Vesting (#)** (1)	**Value Realized on Vesting ($)**
A. James Teague:		
Vesting of phantom unit awards (2)	168,400	$ 4,373,348
Vesting of profits interest award – PubCo I (3)	16,009	419,916
W. Randall Fowler:		
Vesting of phantom unit awards (2)	137,262	3,564,694
Graham W. Bacon:		
Vesting of phantom unit awards (2)	69,000	1,791,930
Vesting of profits interest award – PubCo I (3)	18,296	479,904
Brent B. Secrest:		
Vesting of phantom unit awards (2)	33,125	860,256
Christian M. Nelly:		
Vesting of phantom unit awards (2)	14,717	382,200

(1) Represents the gross number of Partnership common units acquired upon vesting of phantom unit and profits interest awards, before adjustments for associated tax withholdings.

(2) Value realized on vesting of the phantom unit awards determined by multiplying the gross number of Partnership common units received by the closing price of our common units on the date of vesting.

(3) PubCo I vested in February 2020 and its assets (consisting of Partnership common units) were distributed to its partners, which included Mr. Teague and Mr. Bacon. The value realized on vesting was determined by multiplying the gross number of our common units received by the named executive officer by the closing price of our common units on the date of vesting.

Equity-Based Awards Outstanding at December 31, 2020

The following information summarizes each named executive officer's long-term incentive awards outstanding at December 31, 2020. These amounts are presented on a gross basis and do not reflect any allocation of compensation to affiliates under the ASA.

	Unit Awards	
Award Type/Named Executive Officer	**Number of Units That Have Not Vested (#)** (1)	**Market Value of Units That Have Not Vested ($)** (2,3)
Phantom unit awards: (4)		
A. James Teague	498,800	$ 9,771,492
W. Randall Fowler	453,050	8,875,250
Graham W. Bacon	202,250	3,962,078
Brent B. Secrest	151,250	2,962,988
Christian M. Nelly	71,505	1,400,783
Profits interest awards:		
W. Randall Fowler:		
PrivCo I (5,6)	–	$ 0
Graham W. Bacon:		
EPD IV (7)	–	0
Brent B. Secrest:		
PubCo II (5,8)	–	0
EPD IV (7)	–	0
Christian M. Nelly:		
PubCo II (5,8)	–	0
EPD IV (7)	–	0

(1) Represents the total number of phantom unit awards outstanding for each named executive officer.
(2) With respect to amounts presented for phantom unit awards, the market values were derived by multiplying the total number of awards outstanding for the named executive officer by the closing price of Partnership common units on December 31, 2020 (the last trading day of 2020) of $19.59 per unit.
(3) With respect to amounts presented for the profits interest awards, amount represents the estimated liquidation value to be received by the named executive officer based on the closing price of Partnership common units on December 31, 2020 and the terms of liquidation outlined in the applicable Employee Partnership agreement. There was no residual profits interest in any of the Employee Partnerships due to a decrease in the market value of the Partnership common units they own since the formation date of each respective Employee Partnership.
(4) Of the 1,376,855 phantom unit awards presented in the table, the vesting schedule is as follows: 497,430 in 2021; 407,675 in 2022; 303,500 in 2023 and 168,250 in 2024.
(5) The vesting date of the profits interests awards for PrivCo I and PubCo II is the earlier of (i) February 22, 2023, (ii) the first date on or after September 30, 2020 on which the closing market price of our common units is equal to or greater than $25.41 per unit, (iii) a change of control event, or (iv) dissolution of the applicable Employee Partnership
(6) Mr. Fowler's share of the profits interest in PrivCo I was approximately 15.46% at December 31, 2020.
(7) With respect to EPD IV, the profits interest share held by Messrs. Bacon, Secrest and Nelly at December 31, 2020 was approximately 5.00%, 4.00% and 2.50%, respectively.
(8) With respect to PubCo II, the profits interest share held by Messrs. Secrest and Nelly at December 31, 2020 was approximately 3.25% and 2.60%, respectively.

Phantom unit awards

For a description of phantom unit awards, see "Grants of Equity-Based Awards in Fiscal Year 2020" within this Item 11.

Profits interest awards

For a description of the profits interest awards, see Note 13 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Potential Payments Upon Termination or Change-in-Control

None of the named executive officers have any employment agreements that call for the payment of termination or severance benefits or provide for any payments in the event of a change in control of Enterprise GP. A "change of control" under these awards is generally defined to mean that the descendants, heirs and/or legatees of Dan L Duncan, and/or trusts (including, without limitation, one or more voting trusts) established for their benefit, collectively, cease, directly or indirectly, to control our general partner. Mr. Duncan passed away in March 2010.

The vesting of profits interest awards under the Employee Partnerships is subject to acceleration upon a change of control. In addition, the vesting of equity-based awards under EPCO's long-term incentive plans is subject to acceleration upon a qualifying termination, including termination after a change of control of Enterprise GP. A qualifying termination under such awards generally means a termination as an employee of EPCO or an affiliated group member (i) upon death, (ii) a qualifying long-term disability, (iii) a qualifying retirement, or (iv) within one year after a change of control, other than a termination for cause or termination by such person that is not a qualifying termination for good reason (as such terms are defined in the underlying plan documents).

EPCO has entered into retention bonus agreements with each of Messrs. Teague, Fowler, Bacon, Secrest and Nelly, which are described under "Compensation Discussion and Analysis" within this Part III, Item 11. These agreements provide that, in the event of an involuntary termination of any such person's employment prior to the end of his applicable Retention Period for specified reasons, including death, disability or termination of his employment by EPCO other than for "cause" (as defined in each retention bonus agreement), such person will receive (or in the event of his death, his designated beneficiary will receive), a cash payment equal to a pro-rata amount of his applicable Retention Payment (set forth previously), determined based on the number of days he is employed during the applicable Retention Period over the total number of days in such Retention Period (subject to meeting the Performance Requirement through the termination date).

Compensation Committee Report

We do not have a separate compensation committee. In addition, we do not directly employ or compensate our named executive officers. Rather, under the ASA, we reimburse EPCO for the compensation of our executive officers. As described in Compensation Discussion and Analysis, decisions regarding the compensation of our named executive officers with respect to 2020 were made, as applicable, by EPCO and Enterprise GP's Co-CEOs, CFO and the IPA Subcommittee.

In light of the foregoing, the Board has reviewed and discussed with management the Compensation Discussion and Analysis set forth above and determined that it be included in this annual report for the year ended December 31, 2020.

Submitted by: Randa Duncan Williams
Richard H. Bachmann
A. James Teague
W. Randall Fowler
Carin M. Barth
Murray E. Brasseux
James T. Hackett
William C. Montgomery
John R. Rutherford
Richard S. Snell
Harry P. Weitzel

Notwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the Securities Exchange Act, as amended, that incorporate future filings, including this annual report, in whole or in part, the foregoing Compensation Committee Report shall not be incorporated by reference into any such filings.

Compensation Committee Interlocks and Insider Participation

None of the directors or executive officers of Enterprise GP served as members of the compensation committee of another entity that has or had an executive officer who served as a member of our Board during the year ended December 31, 2020. As previously noted, we do not have a separate compensation committee. As described in Compensation Discussion and Analysis, decisions regarding the compensation of our named executive officers with respect to 2020 were made, as applicable, by EPCO and Enterprise GP's Co-CEOs, CFO and the IPA Subcommittee.

Pay Ratio Disclosure

The median of the total annual compensation of all employees of EPCO, other than our Co-CEOs, was $122,526 for the year ended December 31, 2020 (the "fiscal 2020 median total annual compensation"). Mr. Teague and Mr. Fowler served as Co-CEOs of Enterprise GP during the year ended December 31, 2020. Mr. Teague's fiscal 2020 annual total compensation was $10,649,369 and Mr. Fowler's fiscal 2020 annual total compensation allocated to us was $7,948,518. The ratio of the fiscal 2020 median total annual compensation to Mr. Teague's fiscal 2020 annual total compensation was 87:1. The ratio of the fiscal 2020 median total annual compensation to Mr. Fowler's fiscal 2020 annual total compensation was 65:1.

The fiscal 2020 median total annual compensation was determined as follows:

- First, a list was prepared of all active EPCO employees, excluding Mr. Teague, Mr. Fowler and those on long-term disability, that devote all or a substantial portion of their time to our consolidated businesses and affairs. This list was based on employee information as of December 31, 2020. There are approximately 7,130 EPCO personnel who spend all or a substantial portion of their time engaged in our business.

- Second, basic wage data for each active EPCO employee, excluding Mr. Teague, Mr. Fowler and those on long-term disability, was extracted from Form W-2 information provided to the Internal Revenue Service for fiscal 2020. This information was then sorted and the employee who earned the median compensation (the "median employee") was selected from the list.

- Third, once the median employee was selected, his or her respective total annual compensation for 2020 was determined using the same method used to determine Mr. Teague's and Mr. Fowler's total annual compensation for 2020 as presented in the Summary Compensation Table within this Part III, Item 11.

Director Compensation

For the year ended December 31, 2020, the independent voting directors of Enterprise GP were compensated as follows:

- each received an $87,049 annual cash retainer and an annual grant of our common units having a fair market value, based on the closing price of our common units on the trading day immediately preceding the date of grant, of $85,000;

- if the individual served as a chairman of the Audit and Conflicts Committee, then such individual received an additional $20,000 annual cash retainer;

- if the individual served as a chairman of the Governance Committee, then such individual received an additional $15,000 annual cash retainer; and,

- for those independent voting directors that served on the Capital Projects Committee, a $2,500 per meeting cash fee for attendance at meetings of this committee.

The compensation program for independent voting directors for 2021 is expected to be the same as 2020 with the exception that the annual cash retainer and equity grant will each increase to $90,000.

We bear all costs attributable to the compensation of independent voting directors of Enterprise GP. The following table summarizes compensation paid to these directors in 2020:

Independent Voting Director	Fees Earned or Paid in Cash ($)	Value of Equity-Based Awards ($)	Total ($)
Carin M. Barth	$ 87,049	$ 85,000	$ 172,049
Murray E. Brasseux	87,049	85,000	172,049
James T. Hackett (1)	102,049	85,000	187,049
William C. Montgomery (2)	107,049	85,000	192,049
John R. Rutherford	87,049	85,000	172,049
Richard S. Snell	87,049	85,000	172,049

(1) Mr. Hackett serves as chairman of the Governance Committee.
(2) Mr. Montgomery serves as chairman of the Audit and Conflicts Committee.

Messrs. Casey, Cunningham and Smith each received $150,000 in cash for their services as advisory directors in 2020. Also, O.S. Andras received $20,000 in cash for his services as an honorary director in 2020. Neither we nor Enterprise GP provide additional compensation to employees of EPCO for their services as voting directors of Enterprise GP. The employees of EPCO who served as voting directors of Enterprise GP in 2020 were Ms. Duncan Williams and Messrs. Bachmann, Teague, Fowler and Weitzel.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS.

Security Ownership of Certain Beneficial Owners

The following table sets forth certain information as of February 19, 2021, regarding each person known by Enterprise GP to beneficially own more than 5% of our limited partner units:

Name and Address of Beneficial Owner	Title of Class	Amount and Nature of Beneficial Ownership	Percent of Class
Randa Duncan Williams (1)	Common Units	702,186,015	32.2%
1100 Louisiana Street, 10th Floor	Series A Cumulative Convertible Preferred Units	15,412	30.6%
Houston, Texas 77002			

(1) For a detailed listing of the ownership amounts that comprise Ms. Duncan Williams' total beneficial ownership of our limited partner units, see the table presented in the following section, "Security Ownership of Management," within this Part III, Item 12.

Ms. Duncan Williams is a DD LLC Trustee and an EPCO Trustee. Ms. Duncan Williams is also currently Chairman and a director of EPCO and Chairman of the Board and a director of Enterprise GP. Ms. Duncan Williams disclaims beneficial ownership of the limited partner units beneficially owned by the EPCO Trustees, except to the extent of her voting and dispositive interests in such units.

Security Ownership of Management

The following tables set forth certain information regarding the beneficial ownership of our limited partner units, as of February 19, 2021 by (i) the current directors of Enterprise GP; (ii) our named executive officers for 2020; and (iii) the current directors and executive officers (including named executive officers) of Enterprise GP as a group. All beneficial ownership information has been furnished by the respective directors and executive officers. Each person has sole voting and dispositive power over the securities shown unless indicated otherwise.

	Positions with Enterprise GP at February 19, 2021	Amount and Nature Of Beneficial Ownership		Percent of Class	
		Common Units	Preferred Units	Common Units	Preferred Units
Randa Duncan Williams:	Director and Chairman of the Board				
Common units:					
Units controlled by EPCO Voting Trust:					
Through EPCO		74,754,703		3.4%	
Through EPCO Holdings, Inc.		593,479,815		27.2%	
Through Employee Partnerships		11,945,636		*	
Units controlled by Alkek and Williams, Ltd.		455,097		*	
Units controlled by Chaswil, Ltd.		75,736		*	
Units controlled by family trusts (1)		21,279,948		*	
Units owned personally (2)		195,080		*	
Preferred units:					
Units controlled by Manxome Investors L.P.			15,412		30.6%
Total for Randa Duncan Williams		702,186,015	15,412	32.2%	30.6%

** Represents a beneficial ownership of less than 1% of class*

(1) The number of common units presented for Ms. Duncan Williams includes common units held by family trusts for which she serves as a director of an entity trustee but has disclaimed beneficial ownership (except to the extent of her pecuniary interest therein).

(2) The number of common units presented for Ms. Duncan Williams includes 9,090 common units held by her spouse and 4,040 common units held jointly with her spouse.

EPCO and its privately held affiliates have pledged 92,976,464 of our common units that they own as security under their credit facilities. These credit facilities include customary provisions regarding potential events of default. As a result, a change in ownership of these units could result if an event of default ultimately occurred.

		Common Units	
	Positions with Enterprise GP at February 19, 2021	**Amount and Nature Of Beneficial Ownership**	**Percent of Class**
Richard H. Bachmann (1)	Director and Vice Chairman of the Board	1,731,611	*
A. James Teague (2,3)	Director and Co-CEO	2,208,826	*
W. Randall Fowler (2,4)	Director, Co-CEO and CFO	1,691,932	*
Carin M. Barth	Director	62,051	*
Murray E. Brasseux (5)	Director	28,398	*
James T. Hackett (6)	Director	280,209	*
William C. Montgomery	Director	57,551	*
John R. Rutherford	Director	32,716	*
Richard S. Snell (7)	Director	84,966	*
Harry P. Weitzel	Director and Executive Vice President, General Counsel and Secretary	106,508	*
Graham W. Bacon (2)	Executive Vice President and Chief Operating Officer	372,901	*
Brent B. Secrest (2)	Executive Vice President and Chief Commercial Officer	128,254	*
Christian M. Nelly (2)	Executive Vice President – Finance and Sustainability and Treasurer	89,212	*
All directors and executive officers (including all named executive officers) of Enterprise GP, as a group (16 individuals in total)		709,302,393	32.5%

** Represents a beneficial ownership of less than 1% of class*

(1) The number of common units presented for Mr. Bachmann includes 9,588 common units held by his spouse.

(2) These individuals are named executive officers for the year ended December 31, 2020.

(3) The number of common units presented for Mr. Teague includes (i) 61,746 common units held by a trust and (ii) 39,055 common units held by his spouse.

(4) The number of common units presented for Mr. Fowler includes 610,000 common units held by a family limited partnership (for which he has disclaimed beneficial ownership except to the extent of his pecuniary interest).

(5) The number of common units presented for Mr. Brasseux includes 2,882 common units held by his spouse.

(6) The number of common units presented for Mr. Hackett includes (i) 9,661 common units held by family trusts and (ii) 33,000 common units held by a family limited partnership.

(7) The number of common units presented for Mr. Snell includes 2,956 common units held by his spouse.

Equity Ownership Guidelines

In order to further align the interests and actions of Enterprise GP's directors and executive officers with our long-term interests and those of Enterprise GP and other unitholders, the Board has adopted and approved certain equity ownership guidelines for Enterprise GP's directors and executive officers. Under these guidelines:

- each non-management director of Enterprise GP is required to own our common units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such non-management director's aggregate annual cash retainer for service on the Board for the most recently completed calendar year; and

- each executive officer of Enterprise GP is required to own our common units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such executive officer's aggregate annual base salary for the most recently completed calendar year.

Securities Authorized for Issuance Under Equity Compensation Plans

The 2008 Plan is EPCO's only long-term incentive plan under which our common units have been authorized for issuance. The 2008 Plan provides for awards of our common units and other rights to our non-management directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the 2008 Plan may be granted in the form of phantom units, DERs, unit options, restricted common units, UARs, unit awards and other unit-based awards or substitute awards.

The following table sets forth certain information regarding the 2008 Plan as of January 1, 2021.

Plan Category	Number of Units to Be Issued Upon Exercise of Outstanding Common Unit Options	Weighted-Average Exercise Price of Outstanding Common Unit Options	Number of Units Remaining Available For Future Issuance Under Equity Compensation Plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by unitholders:			
2008 Plan (1)	–	–	21,229,995
Equity compensation plans not approved by unitholders:			
None	–	–	–
Total for equity compensation plans	–	–	21,229,995

(1) At December 31, 2020, the total number of common units authorized for issuance under the 2008 Plan was 55,000,000 common units. This amount increased by 5,000,000 common units on January 1, 2021 and will increase by an additional 5,000,000 common units subsequently on each January 1 thereafter during the term of the 2008 Plan; provided, however, that in no event shall the maximum aggregate amount available for issuance under the 2008 Plan exceed 70,000,000 common units.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Certain Relationships and Related Transactions

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

Additional information regarding our related party transactions is set forth in Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report and is incorporated by reference into this Part III, Item 13.

Review and Approval of Transactions with Related Parties

We consider transactions between us and our subsidiaries and unconsolidated affiliates, on the one hand, and our executive officers and directors (or their immediate family members), Enterprise GP or its affiliates (including other companies owned or controlled by the DD LLC Trustees or the EPCO Trustees), on the other hand, to be related party transactions. As further described below, our partnership agreement sets forth general procedures by which related party transactions and conflicts of interest may be approved or resolved by Enterprise GP or its Audit and Conflicts Committee. In addition, the Audit and Conflicts Committee charter, Enterprise GP's written internal review and approval policies and procedures (referred to as its "management authorization policy") and the amended and restated ASA with EPCO address specific types of related party transactions, as further described below.

Our Audit and Conflicts Committee is comprised of four independent directors: Messrs. Brasseux, Montgomery, Rutherford and Snell. In accordance with its charter, the Audit and Conflicts Committee reviews and approves related party transactions:

- pursuant to our partnership agreement or the limited liability company agreement of Enterprise GP, as such agreements may be amended from time to time;
- in which an officer or director of Enterprise GP or any of our subsidiaries, or an immediate family member of such an officer or director, has a material financial interest or is otherwise a party;
- when requested to do so by management or the Board;
- with a value of $5 million or more (unless such transaction is equivalent to an arm's length transaction with a third party); or
- that it may otherwise deem appropriate from time to time.

Enterprise GP's management authorization policy generally requires Board approval for asset purchase or sales transactions and capital investments to the extent such transactions have a value in excess of $500 million. Any such transaction would typically also require Audit and Conflicts Committee review under its charter if such transaction is also a related party transaction.

As noted previously, all of our management, administrative and operating functions are performed by employees of EPCO (pursuant to an administrative services agreement, or ASA) or by other service providers. The ASA governs numerous day-to-day transactions between us, Enterprise GP and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our reimbursement to EPCO of costs, without markup or discount, for those services. The ASA was reviewed, approved and recommended to the Board by our Audit and Conflicts Committee, and the Board also approved it upon receiving such recommendation.

Related party transactions that are outside the scope of the ASA and not reviewed by the Audit and Conflicts Committee are subject to Enterprise GP's management authorization policy. This policy, which applies to related party transactions as well as transactions with third parties, specifies thresholds for our general partner's officers and Board to authorize various categories of transactions, including purchases and sales of assets, commercial and financial transactions and legal agreements.

Partnership Agreement Standards for Audit and Conflicts Committee Review

Under our partnership agreement, whenever a potential conflict of interest exists or arises between Enterprise GP or any of its affiliates, on the one hand, and us, any of our subsidiaries or any partner, on the other hand, any resolution or course of action by Enterprise GP or its affiliates in respect of such conflict of interest is permitted and deemed approved by our limited partners, and will not constitute a breach of our partnership agreement or any agreement contemplated by such agreement, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the partnership agreement is deemed to be, fair and reasonable to us; provided that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by a majority of the members of the Audit and Conflicts Committee (i.e., a "Special Approval" is granted) or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from third parties.

The Audit and Conflicts Committee (in connection with its Special Approval process) may consider the following when resolving conflicts of interest:

- the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;
- the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us);
- any customary or accepted industry practices and any customary or historical dealings with a particular party;
- any applicable generally accepted accounting or engineering practices or principles;
- the relative cost of capital of the parties involved and the consequent rates of return to the equity holders of such parties; and
- such additional factors as the Audit and Conflicts Committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

The level of review and work performed by the Audit and Conflicts Committee with respect to a given transaction varies depending upon the nature of the transaction and the scope of the Audit and Conflicts Committee's obligation. Examples of functions the Audit and Conflicts Committee may, as it deems appropriate, perform in the course of reviewing a transaction include, but are not limited to:

- assessing the business rationale for the transaction;
- reviewing the terms and conditions of the proposed transaction, including consideration and financing requirements, if any;
- assessing the effect of the transaction on our results of operations, financial condition, cash available for distribution, properties or prospects;
- conducting due diligence, including interviews and discussions with management and other representatives and reviewing transaction materials and findings of management and other representatives;
- considering the relative advantages and disadvantages of the transactions to the parties involved;

- engaging third party financial advisors to provide financial advice and assistance, including fairness opinions if requested;
- engaging legal advisors; and
- evaluating and negotiating the transaction and recommending for approval or approving the transaction, as the case may be.

Nothing contained in our partnership agreement requires the Audit and Conflicts Committee to consider the interests of any party other than us. In the absence of the Audit and Conflicts Committee or our general partner acting in bad faith, the resolution, action or terms so made, taken or provided (including granting Special Approval) by the Audit and Conflicts Committee or our general partner with respect to such matter are deemed conclusive and binding on all persons (including all of our limited partners) and do not constitute a breach of our partnership agreement, or any other agreement contemplated thereby, or a breach of any standard of care or duty imposed in our partnership agreement or under the Delaware Revised Uniform Limited Partnership Act or any other law, rule or regulation. Our partnership agreement provides that it is presumed that the resolution, action or terms made, taken or provided by the Audit and Conflicts Committee or our general partner were not made, taken or provided in bad faith, and in any proceeding brought by any limited partner or by or on behalf of such limited partner or any other limited partner or us challenging such resolution, action or terms, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Director Independence

Each of the current members of the Audit and Conflicts Committee, namely Messrs. Brasseux, Montgomery, Rutherford and Snell, and two members of the Governance Committee, namely Ms. Barth and Mr. Hackett, have been determined to be independent under the applicable NYSE listing standards and rules of the SEC. For a discussion of independence standards applicable to our Board and factors considered by our Board in making its independence determinations, please refer to "Partnership Governance" included under Part III, Item 10 of this annual report.

Other Matters

An immediate family member of Mr. Teague is an employee of EPCO that performs services on our behalf. This individual does not serve as an executive officer of Enterprise GP, EPCO or any of their respective affiliates, and such individual's compensation and other terms of employment are determined on a basis consistent with EPCO's human resources policies. For 2020, this individual earned total compensation from EPCO of $770 thousand.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

With the approval of the Audit and Conflicts Committee of Enterprise GP, we have engaged Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte & Touche") as our independent registered public accounting firm and principal accountants. The following table summarizes amounts billed to us by Deloitte & Touche for each of the years presented, as applicable:

	For the Year Ended December 31,	
	2020	2019
Audit fees (1)	$5,155,475	$5,091,440

(1) Audit fees for 2020 and 2019 include $50,000 and $40,000, respectively, of charges for audit-related projects that were reimbursed by business partners.

As presented in the preceding table, "Audit Fees" represent amounts billed for each year in connection with (i) the annual audit of our consolidated financial statements filed on Form 10-K and related internal controls over financial reporting, (ii) the quarterly review of our consolidated financial statements filed on Form 10-Q, (iii) standalone annual audits of our consolidated subsidiaries and (iv) those services normally provided by Deloitte & Touche in connection with our statutory and regulatory filings or engagements, including comfort letters, consents and other services related to SEC matters. We did not engage Deloitte & Touche to perform any other services for us during the last two years. We are prohibited from using Deloitte & Touche to perform general bookkeeping, human resources or management functions for us, and any other service not permitted by the PCAOB.

In connection with its oversight responsibilities, the Audit and Conflicts Committee has adopted a pre-approval policy regarding any services to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other. When Deloitte & Touche's services are required, management and Deloitte & Touche discuss the proposed work with the Audit and Conflicts Committee. These discussions typically address the reasons for the project, the scope of the work to be performed and an estimate of the fee to be charged by Deloitte & Touche for such work. The Audit and Conflicts Committee discusses the request with management and Deloitte & Touche and, if the work is deemed necessary and appropriate for Deloitte & Touche to perform, approves the request subject to the fee estimate (the initial "pre-approved" fee amount). If at a later date, it appears that the initial pre-approved fee amount is insufficient to complete the work, management and Deloitte & Touche must present a supplemental request to the Audit and Conflicts Committee to increase the approved amount along with reasons for the increase. Under the pre-approval policy, management cannot act upon its own to authorize an expenditure for Deloitte & Touche services outside of the pre-approved amounts. On a quarterly basis, the Audit and Conflicts Committee is provided a schedule that compares the pre-approved amounts for each primary service category with the actual fees billed for each type of service. We believe the Audit and Conflicts Committee's pre-approval process maintains the independence of Deloitte & Touche from management.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

The following documents are filed as a part of this annual report:

(1) Financial Statements: See "Index to Consolidated Financial Statements" beginning on page F-1 of this annual report for the financial statements included herein.

(2) Financial Statement Schedules: The separate filing of financial statement schedules has been omitted because such schedules are either not applicable or the information called for therein appears in the footnotes of our Consolidated Financial Statements.

(3) Exhibits:

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

2.9	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products GP, LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed September 7, 2010).
2.10	Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010).
2.11	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
2.12	Contribution and Purchase Agreement, dated as of October 1, 2014, by and among Enterprise Products Partners L.P., Oiltanking Holding Americas, Inc. and OTB Holdco, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2014).
2.13	Agreement and Plan of Merger, dated as of November 11, 2014, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPOT MergerCo LLC, Oiltanking Partners, L.P. and OTLP GP, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed November 12, 2014).
2.14	Amendment No. 1 dated as of June 6, 2018 to Contribution and Purchase Agreement, by and among Enterprise Products Partners L.P., Oiltanking Holding Americas, Inc., Enterprise Products Holdings LLC and Marquard & Bahls, AG (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 12, 2018).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.6 to Form 8-K filed November 23, 2010).
3.3	Seventh Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated as of September 30, 2020 (incorporated by reference to Exhibit 3.1 to Form 8-K filed October 1, 2020).
3.4	Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC) (incorporated by reference to Exhibit 3.3 to Form S-1/A Registration Statement, Reg. No. 333-124320, filed by Enterprise GP Holdings L.P. on July 22, 2005).
3.5	Certificate of Amendment to Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC), filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.5 to Form 8-K filed November 23, 2010).
3.6	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC dated effective as of September 7, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 8, 2011).
3.7	Amendment No. 1 to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC, dated effective as of April 26, 2017 (incorporated by reference to Exhibit 3.1 to Form 8-K filed May 2, 2017).
3.8	Amendment No. 2 to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC, dated effective as of November 6, 2019 (incorporated by reference to Exhibit 3.12 to Form 10-Q filed November 8, 2019).
3.9	Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 8, 2007).
3.10	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.11	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).

4.1	Form of Common Unit certificate (incorporated by reference to Exhibit A to Exhibit 3.1 to Form 8-K filed October 1, 2020).
4.2	Description of the Registrant's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 (incorporated by reference to Exhibit 4.2 to Form 10-K filed February 28, 2020).
4.3	Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 14, 2000).
4.4	Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed August 8, 2007).
4.6	Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 6, 2004).
4.7	Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 6, 2004).
4.8	Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 3, 2005).
4.9	Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.10	Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.11	Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.12	Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.13	Nineteenth Supplemental Indenture, dated as of May 20, 2010, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.14	Twentieth Supplemental Indenture, dated as of January 13, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 13, 2011).

4.15	Twenty-First Supplemental Indenture, dated as of August 24, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.16	Twenty-Second Supplemental Indenture, dated as of February 15, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
4.17	Twenty-Third Supplemental Indenture, dated as of August 13, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 13, 2012).
4.18	Twenty-Fourth Supplemental Indenture, dated as of March 18, 2013, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.19	Twenty-Fifth Supplemental Indenture, dated as of February 12, 2014, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.20	Twenty-Sixth Supplemental Indenture, dated as of October 14, 2014, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.21	Twenty-Seventh Supplemental Indenture, dated as of May 7, 2015, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.22	Twenty-Eighth Supplemental Indenture, dated as of April 13, 2016, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 13, 2016).
4.23	Twenty-Ninth Supplemental Indenture, dated as of August 16, 2017, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 16, 2017).
4.24	Thirtieth Supplemental Indenture, dated as of February 15, 2018, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 15, 2018).
4.25	Thirty-First Supplemental Indenture, dated as of February 15, 2018, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed February 15, 2018).
4.26	Thirty-Second Supplemental Indenture, dated as of October 11, 2018, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 11, 2018).
4.27	Thirty-Third Supplemental Indenture, dated as of July 8, 2019, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed July 8, 2019).

4.28	Thirty-Fourth Supplemental Indenture, dated as of January 15, 2020, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 15, 2020).
4.29	Thirty-Fifth Supplemental Indenture, dated as of August 7, 2020, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 7, 2020).
4.30	Form of Global Note representing $499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.31	Form of Global Note representing $350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.32	Form of Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
4.33	Form of Global Note representing $500.0 million principal amount of 5.25% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.34	Form of Global Note representing $600.0 million principal amount of 6.125% Senior Notes due 2039 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.35	Form of Global Note representing $399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit E to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.36	Form of Global Note representing $285.8 million principal amount of Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.37	Form of Global Note representing $1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.38	Form of Global Note representing $600.0 million principal amount of 6.45% Senior Notes due 2040 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.39	Form of Global Note representing $750.0 million principal amount of 5.95% Senior Notes due 2041 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.40	Form of Global Note representing $650.0 million principal amount of 4.05% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.41	Form of Global Note representing $600.0 million principal amount of 5.70% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.42	Form of Global Note representing $750.0 million principal amount of 4.85% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
4.43	Form of Global Note representing $1.1 billion principal amount of 4.45% Senior Notes due 2043 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed August 13, 2012).

4.44	Form of Global Note representing $1.25 billion principal amount of 3.35% Senior Notes due 2023 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.45	Form of Global Note representing $1.0 billion principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.46	Form of Global Note representing $850.0 million principal amount of 3.90% Senior Notes due 2024 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.47	Form of Global Note representing $1.15 billion principal amount of 5.10% Senior Notes due 2045 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.48	Form of Global Note representing $1.15 billion principal amount of 3.75% Senior Notes due 2025 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.49	Form of Global Note representing $400.0 million principal amount of 4.95% Senior Notes due 2054 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.50	Form of Global Note representing $400.0 million principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.51	Form of Global Note representing $875.0 million principal amount of 3.70% Senior Notes due 2026 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.52	Form of Global Note representing $875.0 million principal amount of 4.90% Senior Notes due 2046 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.53	Form of Global Note representing $575.0 million principal amount of 2.85% Senior Notes due 2021 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.4 to Form 8-K filed April 13, 2016).
4.54	Form of Global Note representing $575.0 million principal amount of 3.95% Senior Notes due 2027 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.4 to Form 8-K filed April 13, 2016).
4.55	Form of Global Note representing $100.0 million principal amount of 4.90% Senior Notes due 2046 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.56	Form of Global Note representing $700 million principal amount of Junior Subordinated Notes D due 2077 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed August 16, 2017).
4.57	Form of Global Note representing $1.0 billion principal amount of Junior Subordinated Notes E due 2077 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed August 16, 2017).
4.58	Form of Global Note representing $750.0 million principal amount of 2.80% Senior Notes due 2021 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.4 to Form 8-K filed February 15, 2018).
4.59	Form of Global Note representing $1.25 billion principal amount of 4.25% Senior Notes due 2048 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.4 to Form 8-K filed February 15, 2018).
4.60	Form of Global Note representing $700 million principal amount of Junior Subordinated Notes F due 2078 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed February 15, 2018).

4.61	Form of Global Note representing $750.0 million principal amount of 3.50% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed October 11, 2018).
4.62	Form of Global Note representing $1,000.0 million principal amount of 4.15% Senior Notes due 2028 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed October 11, 2018).
4.63	Form of Global Note representing $1,250.0 million principal amount of 4.80% Senior Notes due 2049 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed October 11, 2018).
4.64	Form of Global Note representing $1,250.0 million principal amount of 3.125% Senior Notes due 2029 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed July 8, 2019).
4.65	Form of Global Note representing $1,250.0 million principal amount of 4.200% Senior Notes due 2050 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed July 8, 2019).
4.66	Form of Global Note representing $1,000.0 million principal amount of 2.800% Senior Notes due 2030 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed January 15, 2020).
4.67	Form of Global Note representing $1,000.0 million principal amount of 3.700% Senior Notes due 2051 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed January 15, 2020).
4.68	Form of Global Note representing $1,000.0 million principal amount of 3.950% Senior Notes due 2060 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed January 15, 2020).
4.69	Form of Global Note representing $250.0 million principal amount of 2.800% Senior Notes due 2030 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed January 15, 2020).
4.70	Form of Global Note representing $1,000.0 million principal amount of 3.200% Senior Notes due 2052 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.4 to Form 8-K filed August 7, 2020).
4.71	Replacement Capital Covenant, dated October 27, 2009, executed by Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.9 to Form 8-K filed October 28, 2009).
4.72	Amendment to Replacement Capital Covenants, dated May 6, 2015, executed by Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.59 to Form 10-Q filed May 8, 2015).
4.73	Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.2 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.74	Supplemental Indenture, dated June 27, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.6 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 14, 2002).
4.75	Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of Jonah Gas Gathering Company (incorporated by reference to Exhibit 4.8 to the Form 10-Q filed by TEPPCO Partners, L.P. on November 7, 2006).

4.76	Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.13 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.77	Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.78	Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed March 1, 2010).
4.79	Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007).
4.80	First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007).
4.81	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.82	Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.83	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed March 1, 2010).
4.84	Registration Rights Agreement, dated as of March 5, 2020, between Enterprise Products Partners L.P. and Skyline North Americas, Inc. (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 5, 2020).
4.85	Equity Distribution Agreement, dated June 24, 2020, by and among Enterprise Products Partners L.P., Enterprise Products OLPGP, Inc., Enterprise Products Operating LLC, Skyline North Americas, Inc. and Morgan Stanley & Co. LLC. (incorporated by reference to Exhibit 1.1 to Form 8-K filed June 25, 2020).
4.86	Specimen Unit Certificate for the Series A Cumulative Convertible Preferred Units, (incorporated by reference to Exhibit B to Exhibit 3.1 to Form 8-K filed October 1, 2020).
4.87	Registration Rights Agreement, dated as of September 30, 2020, by and among Enterprise Products Partners L.P. and the Purchasers party thereto. (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 1, 2020).

10.1***	2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) (incorporated by reference to Annex A to Definitive Proxy Statement filed August 26, 2013).
10.2***	Form of Employee Phantom Unit Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 3, 2021 (incorporated by reference to Exhibit 10.4 to Form 10-K filed February 24, 2017).
10.3***#	Form of Employee Phantom Unit Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan for awards issued on or after February 3, 2021.
10.4	Eighth Amended and Restated Administrative Services Agreement, effective as of February 13, 2015, by and among Enterprise Products Company, EPCO Holdings, Inc., Enterprise Products Holdings LLC, Enterprise Products Partners L.P., Enterprise Products OLPGP, Inc., Enterprise Products Operating LLC and the Oiltanking Parties named therein (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 13, 2015).
10.5	364-Day Revolving Credit Agreement, dated as of September 8, 2020 among Enterprise Products Operating LLC, the Lenders party thereto, and Citibank, N.A. as Administrative Agent (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 11, 2020).
10.6	Guaranty Agreement, dated as of September 8, 2020, by Enterprise Products Partners L.P. in favor of Citibank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed September 11, 2020).
10.7	Revolving Credit Agreement, dated as of September 13, 2017, among Enterprise Products Operating LLC, the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent, Citibank, N.A., DNB Bank ASA, New York Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, Ltd. and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Syndication Agents, and Barclays Bank PLC, Royal Bank of Canada, Sumitomo Mitsui Banking Corporation, SunTrust Bank, The Bank of Nova Scotia and The Toronto-Dominion Bank, New York Branch, as Co-Documentation Agents (incorporated by reference to Exhibit 10.3 to Form 8-K filed September 15, 2017).
10.8	First Amendment to Revolving Credit Agreement, dated as of September 10, 2019, among Enterprise Products Operating LLC, the Lenders party thereto, and Wells Fargo Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.3 to Form 8-K filed September 11, 2019).
10.9	Guaranty Agreement, dated as of September 13, 2017, by Enterprise Products Partners L.P. in favor of Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.4 to Form 8-K filed September 15, 2017).
10.10	Liquidity Option Agreement, dated as of October 1, 2014, between Enterprise Products Partners, L.P., Oiltanking Holding Americas, Inc., and Marquard & Bahls AG (incorporated by reference to Exhibit 10.3 to Form 8-K filed October 1, 2014).
10.11	Support Agreement, dated as of November 11, 2014, by and among Enterprise Products Partners L.P., Enterprise Products Operating LLC and Oiltanking Partners, L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 12, 2014).
10.12***	EPD PubCo Unit I L.P. Amended and Restated Agreement of Limited Partnership dated November 3, 2016 (incorporated by reference to Exhibit 10.17 to Form 10-K filed February 24, 2017).
10.13***	EPD PubCo Unit II L.P. Amended and Restated Agreement of Limited Partnership dated November 3, 2016 (incorporated by reference to Exhibit 10.18 to Form 10-K filed February 24, 2017).
10.14***	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of EPD PubCo Unit II L.P., dated as of September 30, 2020 (incorporated by reference to Exhibit 10.3 to Form 8-K filed October 1, 2020).
10.15***	EPD PrivCo Unit I L.P. Amended and Restated Agreement of Limited Partnership dated November 3, 2016 (incorporated by reference to Exhibit 10.19 to Form 10-K filed February 24, 2017).
10.16***	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of EPD PrivCo Unit I L.P., dated as of September 30, 2020 (incorporated by reference to Exhibit 10.4 to Form 8-K filed October 1, 2020).

10.17***	EPD 2018 Unit IV L.P. Agreement of Limited Partnership dated December 3, 2018 (incorporated by reference to Exhibit 10.1 to Form 8-K filed December 6, 2018).
10.18***	EPCO Unit II L.P. Agreement of Limited Partnership dated December 3, 2018 (incorporated by reference to Exhibit 10.2 to Form 8-K filed December 6, 2018).
10.19	Equity Distribution Agreement, dated December 1, 2017, by and among Enterprise Products Partners L.P., Enterprise Products OLPGP, Inc., Enterprise Products Operating LLC and Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., DNB Markets, Inc., Jefferies LLC, J.P. Morgan Securities LLC, Mizuho Securities USA Inc., Morgan Stanley & Co. LLC, MUFG Securities Americas Inc., Raymond James & Associates, Inc., RBC Capital Markets, LLC, Scotia Capital (USA) Inc., SG Americas Securities, LLC, SMBC Nikko Securities America, Inc., SunTrust Robinson Humphrey, Inc., TD Securities (USA) LLC, UBS Securities LLC, USCA Securities LLC and Wells Fargo Securities, LLC. (incorporated by reference to Exhibit 1.1 to Form 8-K filed December 1, 2017).
10.20	Series A Cumulative Convertible Preferred Unit Purchase Agreement, dated as of September 30, 2020, by and among Enterprise Products Partners L.P. and the Purchasers party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K filed October 1, 2020).
10.21	Securities Exchange Agreement, dated as of September 30, 2020, by and between Enterprise Products Partners L.P. and OTA Holdings, Inc. (incorporated by reference to Exhibit 10.2 to Form 8-K filed October 1, 2020).
10.22***	Retention Bonus Agreement between A. James Teague and Enterprise Products Company dated effective April 15, 2019 (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 18, 2019).
10.23***	Retention Bonus Agreement between W. Randall Fowler and Enterprise Products Company dated effective April 15, 2019 (incorporated by reference to Exhibit 10.2 to Form 8-K filed April 18, 2019).
10.24***	Retention Bonus Agreement between Graham W. Bacon and Enterprise Products Company dated effective April 15, 2019 (incorporated by reference to Exhibit 10.3 to Form 8-K filed April 18, 2019).
10.25***	Retention Bonus Agreement between Brent B. Secrest and Enterprise Products Company dated effective April 15, 2019 (incorporated by reference to Exhibit 10.4 to Form 8-K filed April 18, 2019).
10.26***#	Retention Bonus Agreement between Christian M. Nelly and Enterprise Products Company dated effective April 15, 2019.
21.1#	List of Consolidated Subsidiaries as of February 1, 2021.
22.1#	List of Issuers of Debt Securities Guaranteed by Enterprise Products Partners L.P. and Associated Securities at December 31, 2020.
23.1#	Consent of Deloitte & Touche LLP.
31.1#	Sarbanes-Oxley Section 302 certification of A. James Teague for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2020.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2020.
32.1#	Sarbanes-Oxley Section 906 certification of A. James Teague for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2020.
32.2#	Sarbanes-Oxley Section 906 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2020.
101#	Interactive data files pursuant to Rule 405 of Regulation S-T formatted in iXBRL (Inline Extensible Business Reporting Language) in this Form 10-K include the: (i) Consolidated Balance Sheets, (ii) Statements of Consolidated Operations, (iii) Statements of Consolidated Comprehensive Income, (iv) Statements of Consolidated Cash Flows, (v) Statements of Consolidated Equity and (vi) Notes to the Consolidated Financial Statements.
104#	Cover Page Interactive Data File (embedded within the Inline XBRL document).

*	With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file numbers for Enterprise Products Partners L.P., Enterprise GP Holdings L.P, TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC are 1-14323, 1-32610, 1-10403 and 1-13603, respectively.
***	Identifies management contract and compensatory plan arrangements.
#	Filed with this report.

ITEM 16. FORM 10-K SUMMARY.

Not included.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on March 1, 2021.

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

By: Enterprise Products Holdings LLC, as General Partner

By: */s/ R. Daniel Boss*
Name: R. Daniel Boss
Title: Executive Vice President – Accounting, Risk Control and Information Technology of the General Partner

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on March 1, 2021.

Signature	Title (Position with Enterprise Products Holdings LLC)
/s/ Randa Duncan Williams Randa Duncan Williams	Director and Chairman of the Board
/s/ Richard H. Bachmann Richard H. Bachmann	Director and Vice-Chairman of the Board
/s/ A. James Teague A. James Teague	Director and Co-Chief Executive Officer
/s/ W. Randall Fowler W. Randall Fowler	Director, Co-Chief Executive Officer and Chief Financial Officer
/s/ Harry P. Weitzel Harry P. Weitzel	Director and Executive Vice President, General Counsel and Secretary
/s/ Carin M. Barth Carin M. Barth	Director
/s/ Murray E. Brasseux Murray E. Brasseux	Director
/s/ James T. Hackett James T. Hackett	Director
/s/ William C. Montgomery William C. Montgomery	Director
/s/ John R. Rutherford John R. Rutherford	Director
/s/ Richard S. Snell Richard S. Snell	Director
/s/ R. Daniel Boss R. Daniel Boss	Executive Vice President – Accounting, Risk Control and Information Technology
/s/ Michael W. Hanson Michael W. Hanson	Vice President and Principal Accounting Officer

Item 8. Financial Statements and Supplementary Data.

ENTERPRISE PRODUCTS PARTNERS L.P.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products Holdings LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2020 and 2019, the related statements of consolidated operations, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2021, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing a separate opinion on the critical audit matters or on the accounts or disclosures to which they relate.

Goodwill—Natural Gas Pipelines & Services Reporting Unit—Refer to Note 2 and Note 6 to the consolidated financial statements

Critical Audit Matter Description

Goodwill amounts are assessed for impairment on an annual basis or when impairment indicators are present. In performing the goodwill assessment, the estimated fair value of the reporting unit to which the goodwill is assigned is determined and compared to its carrying value. If the fair value of the reporting unit is less than its carrying value (including associated goodwill), a non-cash impairment charge to earnings is recorded to reduce the carrying value of the goodwill to its estimated fair value. The Company's goodwill balance was $5,448.9 million as of December 31, 2020. Reporting unit estimated fair values are based on assumptions regarding the future economic prospects of the businesses that comprise each reporting unit, including (i) forecasted operating margin for the associated assets, including any planned capital projects and related contract fees; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates. The Company recorded an impairment charge of $296.3 million related to the natural gas pipelines & services reporting unit, which represented the entire amount of the goodwill attributable to this reporting unit.

We have identified goodwill associated with the natural gas pipelines & services reporting unit as a critical audit matter due to significant judgments and assumptions made by management related to planned capital projects and related contract fees underlying the forecasted operating margin, the long-term growth rate for cash flows beyond the discrete forecast period, and the discount rate on the Company's estimated fair value of the natural gas pipelines & services reporting unit. Auditing management's judgments required especially subjective judgment and an increased extent of effort, including the need to involve our fair value specialists, when performing audit procedures to evaluate the reasonableness of management's estimates and assumptions for this reporting unit.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's judgments regarding forecasted operating margin and the selection of the long-term growth rate and discount rate for this reporting unit included the following, among others:

- We tested the effectiveness of controls over goodwill, including those over the assumptions related to planned capital projects and related contract fees underlying the forecasted operating margin, the long-term growth rate for cash flows beyond the discrete forecast period, and the discount rate.

- We evaluated management's ability to reasonably forecast operating margin by performing a look-back test comparing actual results to management's historical forecasts.

- We evaluated the reasonableness of management's operating margin forecast for planned capital projects and related contract fees by comparing the forecast to:

  - Internal communications to management and the Board of Directors regarding the projects.

  - Forecasted information regarding the projects included in analyst and industry reports for the Company and certain of its peer companies.

- With the assistance of our fair value specialists, we evaluated the reasonableness of the long-term growth rate for cash flows beyond the discrete forecast period and the discount rate by:

  - Testing the source information underlying the determination of the long-term growth rate and discount rate, and the mathematical accuracy of the calculations.

  - Developing a range of independent estimates and comparing those to the long-term growth rate and discount rate selected by management.

Property, Plant and Equipment, net – Marine Transportation Assets Group Impairment - Refer to Notes 2, 4, and 14 to the consolidated financial statements

Critical Audit Matter Description

Long-lived assets, which include property, plant and equipment, are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Long-lived assets with carrying values that are not expected to be recovered through undiscounted future cash flows are written down to their estimated fair values. As a result of management's recoverability test, a non-cash asset impairment charge of $256.7 million was recognized for the marine transportation asset group, which reduced the carrying value of this asset group to its estimated fair value of $410.0 million at December 31, 2020.

We have identified the non-cash impairment charge associated with management's fair value estimate of the marine transportation asset group as a critical audit matter due to significant judgments and assumptions made by management related to i) the forecasted operating margin, ii) the long-term growth rate for cash flows beyond the discrete forecast period, and iii) the discount rate. Auditing management's judgments required especially subjective judgment and an increased extent of effort, including the need to involve our fair value specialists, when performing audit procedures to evaluate the reasonableness of management's estimates and assumptions.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's judgments used within its recoverability test and the associated fair value estimate included the following, among others:

- We tested the effectiveness of property, plant and equipment controls over the review of assumptions underlying the forecasted operating margin, the long-term growth rate for cash flows beyond the discrete forecast period, and the discount rate.

- We evaluated management's ability to reasonably forecast operating margin by:

  - Performing a look-back test comparing actual results to management's historical forecasts.

  - Performing a sensitivity analysis to evaluate the change in the fair value estimate that would result from changes in certain underlying assumptions.

- With the assistance of our fair value specialists, we evaluated the reasonableness of the long-term growth rate for cash flows beyond the discrete forecast period and the discount rate by:

  - Testing the source information underlying the determination of the long-term growth rate and discount rate, and the mathematical accuracy of the calculations.

  - Developing a range of independent estimates and comparing those to the long-term growth rate and discount rate selected by management.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2021

We have served as the Company's auditor since 1997.

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

	December 31, 2020	December 31, 2019
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,059.9	$ 334.7
Restricted cash	98.2	75.3
Accounts receivable – trade, net of allowance for doubtful accounts of $46.5 at December 31, 2020 and $12.4 at December 31, 2019	4,802.6	4,873.6
Accounts receivable – related parties	5.6	2.5
Inventories	3,303.5	2,091.4
Derivative assets (see Note 14)	228.6	127.2
Prepaid and other current assets	411.0	358.2
Total current assets	9,909.4	7,862.9
Property, plant and equipment, net	41,912.8	41,603.4
Investments in unconsolidated affiliates	2,429.2	2,600.2
Intangible assets, net of accumulated amortization of $1,826.7 at December 31, 2020 and $1,687.5 at December 31, 2019 (see Note 6)	3,309.1	3,449.0
Goodwill (see Note 6)	5,448.9	5,745.2
Other assets	1,097.3	472.5
Total assets	$ 64,106.7	$ 61,733.2
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 7)	$ 1,325.0	$ 1,981.9
Accounts payable – trade	704.6	1,004.5
Accounts payable – related parties	149.5	162.3
Accrued product payables	5,395.4	4,915.7
Accrued interest	455.6	431.7
Derivative liabilities (see Note 14)	349.2	122.4
Other current liabilities	608.7	511.2
Total current liabilities	8,988.0	9,129.7
Long-term debt (see Note 7)	28,540.7	25,643.2
Deferred tax liabilities (see Note 16)	464.7	100.4
Other long-term liabilities	686.6	1,032.4
Commitments and contingent liabilities (see Note 17)		
Redeemable preferred limited partner interests: (see Note 8)		
Series A cumulative convertible preferred units (“preferred units”) (50,138 units outstanding at December 31, 2020)	49.3	–
Equity: (see Note 8)		
Partners’ equity:		
Common limited partner interests (2,182,308,958 units issued and outstanding at December 31, 2020 and 2,189,226,130 units issued and outstanding at December 31, 2019)	25,766.6	24,692.6
Treasury units, at cost	(1,297.3)	–
Accumulated other comprehensive income (loss)	(165.2)	71.4
Total partners’ equity	24,304.1	24,764.0
Noncontrolling interests in consolidated subsidiaries	1,073.3	1,063.5
Total equity	25,377.4	25,827.5
Total liabilities, preferred units, and equity	$ 64,106.7	$ 61,733.2

See Notes to Consolidated Financial Statements.

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

	For the Year Ended December 31,		
	2020	**2019**	**2018**
Revenues:			
Third parties	$ 27,163.0	$ 32,721.9	$ 36,426.5
Related parties	36.7	67.3	107.7
Total revenues (see Note 9)	27,199.7	32,789.2	36,534.2
Costs and expenses:			
Operating costs and expenses:			
Third party and other costs	21,160.5	25,649.8	29,991.2
Related parties	1,210.6	1,412.0	1,406.1
Total operating costs and expenses	22,371.1	27,061.8	31,397.3
General and administrative costs:			
Third party and other costs	83.4	75.3	77.4
Related parties	136.2	136.4	130.9
Total general and administrative costs	219.6	211.7	208.3
Total costs and expenses (see Note 10)	22,590.7	27,273.5	31,605.6
Equity in income of unconsolidated affiliates	426.1	563.0	480.0
Operating income	5,035.1	6,078.7	5,408.6
Other income (expense):			
Interest expense	(1,287.4)	(1,243.0)	(1,096.7)
Change in fair market value of Liquidity Option (see Note 17)	(2.3)	(119.6)	(56.1)
Gain on step acquisition of unconsolidated affiliate (see Note 12)	–	–	39.4
Interest income	13.4	11.6	3.6
Other, net	2.6	5.0	–
Total other expense, net	(1,273.7)	(1,346.0)	(1,109.8)
Income before income taxes	3,761.4	4,732.7	4,298.8
Benefit from (provision for) income taxes (see Note 16)	124.3	(45.6)	(60.3)
Net income	3,885.7	4,687.1	4,238.5
Net income attributable to noncontrolling interests (see Note 8)	(110.1)	(95.8)	(66.1)
Net income attributable to preferred units (see Note 8)	(0.9)	–	–
Net income attributable to common unitholders	$ 3,774.7	$ 4,591.3	$ 4,172.4
Earnings per unit: (see Note 11)			
Basic earnings per common unit	$ 1.71	$ 2.09	$ 1.91
Diluted earnings per common unit	$ 1.71	$ 2.09	$ 1.91

See Notes to Consolidated Financial Statements.

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

	For the Year Ended December 31,		
	2020	2019	2018
Net income	$ 3,885.7	$ 4,687.1	$ 4,238.5
Other comprehensive income (loss):			
Cash flow hedges: (see Note 14)			
Commodity hedging derivative instruments:			
Changes in fair value of cash flow hedges	124.4	44.1	293.2
Reclassification of gains to net income	(272.7)	(141.7)	(130.4)
Interest rate hedging derivative instruments:			
Changes in fair value of cash flow hedges	(127.5)	81.4	22.2
Reclassification of losses to net income	39.3	37.3	38.1
Total cash flow hedges	(236.5)	21.1	223.1
Other	(0.1)	(0.6)	(0.5)
Total other comprehensive income (loss)	(236.6)	20.5	222.6
Comprehensive income	3,649.1	4,707.6	4,461.1
Comprehensive income attributable to noncontrolling interests	(110.1)	(95.8)	(66.1)
Comprehensive income attributable to preferred units (see Note 8)	(0.9)	–	–
Comprehensive income attributable to common unitholders	$ 3,538.1	$ 4,611.8	$ 4,395.0

See Notes to Consolidated Financial Statements.

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

	For the Year Ended December 31,		
	2020	2019	2018
Operating activities:			
Net income	$ 3,885.7	$ 4,687.1	$ 4,238.5
Reconciliation of net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	2,071.9	1,949.3	1,791.6
Impairment of goodwill (see Notes 2 and 6)	296.3	–	–
Impairment of assets other than goodwill (see Notes 2 and 4)	594.3	132.8	50.5
Equity in income of unconsolidated affiliates	(426.1)	(563.0)	(480.0)
Distributions received from unconsolidated affiliates attributable to earnings	426.6	568.0	479.4
Net gains attributable to asset sales (see Note 19)	(4.4)	(5.7)	(28.7)
Deferred income tax expense (benefit)	(147.6)	20.0	21.4
Change in fair market value of derivative instruments	(79.3)	27.2	17.8
Change in fair market value of Liquidity Option (see Note 17)	2.3	119.6	56.1
Gain on step acquisition of unconsolidated affiliate (see Note 12)	–	–	(39.4)
Non-cash expense related to long-term operating leases (see Note 17)	39.0	42.8	–
Net effect of changes in operating accounts (see Note 19)	(767.5)	(457.4)	16.2
Other operating activities	0.3	(0.2)	2.9
Net cash flows provided by operating activities	5,891.5	6,520.5	6,126.3
Investing activities:			
Capital expenditures	(3,287.9)	(4,531.7)	(4,223.2)
Cash used for business combinations, net of cash received (see Note 12)	–	–	(150.6)
Investments in unconsolidated affiliates	(15.6)	(111.6)	(113.6)
Distributions received from unconsolidated affiliates attributable to the return of capital	187.5	63.3	50.0
Proceeds from asset sales (see Note 19)	12.8	20.6	161.2
Other investing activities	(17.5)	(16.1)	(5.4)
Cash used in investing activities	(3,120.7)	(4,575.5)	(4,281.6)
Financing activities:			
Borrowings under debt agreements	6,672.1	58,172.6	79,588.7
Repayments of debt	(4,406.6)	(56,716.5)	(77,957.1)
Debt issuance costs	(46.3)	(27.6)	(49.1)
Monetization of interest rate derivative instruments (see Note 14)	(33.3)	–	22.1
Cash distributions paid to common unitholders (see Note 8)	(3,891.0)	(3,839.8)	(3,726.9)
Cash payments made in connection with distribution equivalent rights	(27.1)	(22.1)	(17.7)
Cash distributions paid to noncontrolling interests (see Note 8)	(131.3)	(106.2)	(81.6)
Cash contributions from noncontrolling interests (see Note 8)	30.9	632.8	238.1
Net cash proceeds from the issuance of common units	–	82.2	538.4
Repurchase of common units under buyback programs (see Note 8)	(186.3)	(81.1)	(30.8)
Net cash proceeds from the issuance of preferred units (see Note 8)	31.5	–	–
Other financing activities	(35.3)	(39.4)	(29.0)
Cash used in financing activities	(2,022.7)	(1,945.1)	(1,504.9)
Net change in cash and cash equivalents, including restricted cash	748.1	(0.1)	339.8
Cash and cash equivalents, including restricted cash, January 1	410.0	410.1	70.3
Cash and cash equivalents, including restricted cash, December 31	$ 1,158.1	$ 410.0	$ 410.1

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED EQUITY
(See Note 8 for Unit History, Accumulated Other Comprehensive Income (Loss) and Noncontrolling Interests)
(Dollars in millions)

	Partners' Equity				
	Common Limited Partner Interests	Treasury Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests in Consolidated Subsidiaries	Total
Balance, December 31, 2017	$ 22,718.9	$ –	$ (171.7)	$ 225.2	$ 22,772.4
Net income	4,172.4	–	–	66.1	4,238.5
Cash distributions paid to common unitholders	(3,726.9)	–	–	–	(3,726.9)
Cash payments made in connection with distribution equivalent rights	(17.7)	–	–	–	(17.7)
Cash distributions paid to noncontrolling interests	–	–	–	(81.6)	(81.6)
Cash contributions from noncontrolling interests	–	–	–	238.1	238.1
Net cash proceeds from the issuance of common units	538.4	–	–	–	538.4
Common units issued in connection with employee compensation	39.1	–	–	–	39.1
Common units issued in connection with land acquisition	30.0	–	–	–	30.0
Repurchase and cancellation of common units under Legacy Buyback Program	(30.8)	–	–	–	(30.8)
Amortization of fair value of equity-based awards	104.7	–	–	–	104.7
Cash flow hedges	–	–	223.1	–	223.1
Other, net	(25.5)	–	(0.5)	(9.1)	(35.1)
Balance, December 31, 2018	23,802.6	–	50.9	438.7	24,292.2
Net income	4,591.3	–	–	95.8	4,687.1
Cash distributions paid to common unitholders	(3,839.8)	–	–	–	(3,839.8)
Cash payments made in connection with distribution equivalent rights	(22.1)	–	–	–	(22.1)
Cash distributions paid to noncontrolling interests	–	–	–	(106.2)	(106.2)
Cash contributions from noncontrolling interests	–	–	–	632.8	632.8
Net cash proceeds from the issuance of common units	82.2	–	–	–	82.2
Common units issued in connection with employee compensation	45.6	–	–	–	45.6
Repurchase and cancellation of common units under 2019 Buyback Program	(81.1)	–	–	–	(81.1)
Amortization of fair value of equity-based awards	143.3	–	–	–	143.3
Cash flow hedges	–	–	21.1	–	21.1
Other, net	(29.4)	–	(0.6)	2.4	(27.6)
Balance, December 31, 2019	24,692.6	–	71.4	1,063.5	25,827.5
Net income	3,774.7	–	–	110.1	3,884.8
Cash distributions paid to common unitholders	(3,891.0)	–	–	–	(3,891.0)
Cash payments made in connection with distribution equivalent rights	(27.1)	–	–	–	(27.1)
Cash distributions paid to noncontrolling interests	–	–	–	(131.3)	(131.3)
Cash contributions from noncontrolling interests	–	–	–	30.9	30.9
Repurchase and cancellation of common units under 2019 Buyback Program	(186.3)	–	–	–	(186.3)
Common units issued to Skyline North Americas, Inc. in connection with settlement of Liquidity Option (see Note 8)	1,297.3	–	–	–	1,297.3
Treasury units acquired in connection with settlement of Liquidity Option, at cost (see Note 8)	–	(1,297.3)	–	–	(1,297.3)
Common units exchanged for preferred units, with common units received being immediately cancelled (see Note 8)	(17.5)	–	–	–	(17.5)
Amortization of fair value of equity-based awards	158.6	–	–	–	158.6
Cash flow hedges	–	–	(236.5)	–	(236.5)
Other, net	(34.7)	–	(0.1)	0.1	(34.7)
Balance, December 31, 2020	$ 25,766.6	$ (1,297.3)	$ (165.2)	$ 1,073.3	$ 25,377.4

See Notes to Consolidated Financial Statements.

KEY REFERENCES USED IN THESE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Unless the context requires otherwise, references to "we," "us," or "our" within these Notes to Consolidated Financial Statements are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to the "Partnership" mean Enterprise Products Partners L.P. on a standalone basis.

References to "EPO" mean Enterprise Products Operating LLC, which is an indirect wholly owned subsidiary of the Partnership, and its consolidated subsidiaries, through which the Partnership conducts its business. We are managed by our 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) W. Randall Fowler, who is also a director and the Co-Chief Executive Officer and Chief Financial Officer of Enterprise GP. Ms. Duncan Williams and Messrs. Bachmann and Fowler also currently serve as managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company, a privately held Texas corporation, and its privately held affiliates. 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) Mr. Bachmann, who serves as the President and Chief Executive Officer of EPCO; and (iii) Mr. Fowler, who serves as an Executive Vice President and the Chief Financial Officer of EPCO. Ms. Duncan Williams and Messrs. Bachmann and Fowler also currently serve as directors of EPCO.

We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates under the collective common control of the DD LLC Trustees and the EPCO Trustees. EPCO, together with its privately held affiliates, owned approximately 32.2% of the Partnership's common units outstanding and 30.2% of its preferred units outstanding at December 31, 2020.

All statistical data (e.g., pipeline mileage, processing capacity and similar operating metrics) in these notes to consolidated financial statements are unaudited.

With the exception of per unit amounts, or as noted within the context of each disclosure, the dollar amounts presented in the tabular data within these disclosures are stated in millions of dollars.

Note 1. Partnership Organization and Operations

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." Our preferred units are not publicly traded. We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products. We are owned by our limited partners (preferred and common unitholders) from an economic perspective. Enterprise GP, which owns a non-economic general partner interest in us, manages our Partnership. We conduct substantially all of our business operations through EPO and its consolidated subsidiaries.

Our fully integrated, midstream energy asset network (or "value chain") 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 include:

- natural gas gathering, treating, processing, transportation and storage;
- NGL transportation, fractionation, storage, and marine terminals (including those used to export liquefied petroleum gases, or "LPG," and ethane);
- crude oil gathering, transportation, storage, and marine terminals;
- propylene production facilities (including propane dehydrogenation ("PDH") facilities), butane isomerization, octane enhancement, isobutane dehydrogenation ("iBDH") and high purity isobutylene ("HPIB") production facilities;
- petrochemical and refined products transportation, storage, and marine terminals (including those used to export ethylene and polymer grade propylene; and
- a marine transportation business that operates on key U.S. inland and intracoastal waterway systems.

Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. See Note 15 for information regarding related party matters.

Our operations are reported under four business segments: NGL Pipelines & Services, Crude Oil Pipelines & Services, Natural Gas Pipelines & Services and Petrochemical & Refined Products Services. See Note 10 for additional information regarding our business segments.

Note 2. Summary of Significant Accounting Policies

Our consolidated financial statements are prepared on the accrual basis of accounting in accordance with U.S. generally accepted accounting principles ("GAAP").

Allowance for Doubtful Accounts

We estimate our allowance for doubtful accounts at each reporting date using a current expected credit loss model, which requires the measurement of expected credit losses for financial assets (e.g., accounts receivable) based on historical experience with customers, current economic conditions, and reasonable and supportable forecasts. We may also increase the allowance for doubtful accounts in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties.

The following table presents our allowance for doubtful accounts activity for the years indicated:

	For the Year Ended December 31,		
	2020	2019	2018
Balance at beginning of period	$ 12.4	$ 11.5	$ 12.1
Charged to costs and expenses	8.4	1.2	0.7
Charged to other accounts (1)	28.7	–	–
Deductions	(3.0)	(0.3)	(1.3)
Balance at end of period	$ 46.5	$ 12.4	$ 11.5

(1) Amount presented for 2020 primarily relates to the reclassification of deferred revenue balances to allowance for doubtful accounts in connection with customer bankruptcies and contractual disputes.

Cash, Cash Equivalents and Restricted Cash

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase.

Restricted cash primarily represents amounts held in segregated bank accounts by our clearing brokers as margin in support of our commodity derivative instruments portfolio and related physical purchases and sales of natural gas, NGLs, crude oil, refined products and power. Additional cash may be restricted to maintain our commodity derivative instruments portfolio as prices fluctuate or margin requirements change. See Note 14 for information regarding our derivative instruments and hedging activities.

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

	December 31,	
	2020	2019
Cash and cash equivalents	$ 1,059.9	$ 334.7
Restricted cash	98.2	75.3
Total cash, cash equivalents and restricted cash shown in the Statements of Consolidated Cash Flows	$ 1,158.1	$ 410.0

Consolidation Policy

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all intercompany accounts and transactions. We also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership. We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own. Third party or affiliate ownership interests in our controlled subsidiaries are presented as noncontrolling interests. See Note 8 for information regarding noncontrolling interests.

If the entity is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50%, unless our interest is so minor that we have virtually no influence over the investee's operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the investee's operating and financial policies. In consolidation, we eliminate our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates to the extent such amounts remain on our Consolidated Balance Sheets (or those of our equity method investments) in inventory or similar accounts.

Contingencies

Certain conditions may exist as of the date our consolidated financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the need for accounting recognition or disclosure of these contingencies, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in such proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

We accrue an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when the likelihood of loss is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material to our consolidated financial statements, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. See Note 17 for additional information regarding our contingencies.

Current Assets and Current Liabilities

We present, as individual captions in our Consolidated Balance Sheets, all components of current assets and current liabilities that exceed 5% of total current assets and current liabilities, respectively.

Derivative Instruments

We use derivative instruments such as futures, swaps, forward contracts and other arrangements to manage price risks associated with inventories, firm commitments, interest rates and certain anticipated future commodity transactions. To qualify for hedge accounting, the hedged item must expose us to risk and the related derivative instrument must reduce the exposure to that risk and meet specific hedge documentation requirements related to designation dates, expectations for hedge effectiveness and the probability that hedged future transactions will occur as forecasted. We formally designate derivative instruments as hedges and document and assess their effectiveness at inception of the hedge and on a monthly basis thereafter. Forecasted transactions are evaluated for the probability of occurrence and are periodically back-tested once the forecasted period has passed to determine whether forecasted transactions are probable of occurring in the future.

We are required to recognize derivative instruments at fair value as either assets or liabilities on our Consolidated Balance Sheets unless such instruments meet certain normal purchase/normal sale criteria. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of derivative instruments are reported in different ways, depending on the nature and effectiveness of the hedging activities to which they relate. After meeting specified conditions, a qualified derivative may be designated as a total or partial hedge of:

- Changes in the fair value of a recognized asset or liability, or an unrecognized firm commitment – In a fair value hedge, gains and losses for both the derivative instrument and the hedged item are recognized in income during the period of change.

- Variable cash flows of a forecasted transaction – In a cash flow hedge, the change in the fair value of the hedge is reported in other comprehensive income (loss) and is reclassified to earnings when the forecasted transaction affects earnings.

An effective hedge relationship is one in which the change in fair value of a derivative instrument can be expected to offset 80% to 125% of the changes in fair value of a hedged item at inception and throughout the life of the hedging relationship. The effective portion of a hedge relationship is the amount by which the derivative instrument exactly offsets the change in fair value of the hedged item during the reporting period.

A contract designated as a cash flow hedge of an anticipated transaction that is not probable of occurring is immediately recognized in earnings.

Certain of our derivative instruments do not qualify for hedge accounting treatment; therefore, these instruments are accounted for using mark-to-market accounting.

For certain physical forward commodity derivative contracts, we apply the normal purchase/normal sale exception, whereby changes in the mark-to-market values of such contracts are not recognized in income. As a result, the revenues and expenses associated with such physical transactions are recognized during the period when volumes are physically delivered or received. Physical forward commodity contracts subject to this exception are evaluated for the probability of future delivery and are periodically back-tested once the forecasted period has passed to determine whether similar forward contracts are probable of physical delivery in the future. See Note 14 for additional information regarding our derivative instruments.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2020, none of our estimated environmental remediation liabilities were discounted to present value since the ultimate amount and timing of cash payments for such liabilities were not readily determinable.

The following table presents the activity of our environmental reserves for the years indicated:

	For the Year Ended December 31,		
	2020	2019	2018
Balance at beginning of period	$ 7.2	$ 6.9	$ 11.6
Charged to costs and expenses	6.2	12.3	8.2
Acquisition-related additions and other	2.6	2.5	1.7
Deductions	(11.5)	(14.5)	(14.6)
Balance at end of period	$ 4.5	$ 7.2	$ 6.9

At December 31, 2020 and 2019, $3.8 million and $5.8 million, respectively, of our environmental reserves were classified as current liabilities.

Estimates

Preparing our consolidated financial statements in conformity with U.S. GAAP requires us to make estimates that affect amounts presented in the financial statements. Our most significant estimates relate to (i) the useful lives and depreciation/amortization methods used for fixed and identifiable intangible assets; (ii) measurement of fair value and projections used in impairment testing of fixed and intangible assets (including goodwill); (iii) contingencies; and (iv) revenue and expense accruals.

Actual results could differ materially from our estimates. On an ongoing basis, we review our estimates based on currently available information. Any changes in the facts and circumstances underlying our estimates may require us to update such estimates, which could have a material impact on our consolidated financial statements.

Fair Value Measurements

Our recurring and nonrecurring fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk, in the principal market of the asset or liability at a specified measurement date. Recognized valuation techniques (such as the income or market approaches) employ inputs such as contractual prices, quoted market prices or rates, operating costs, discount factors and business growth rates. These inputs may be either readily observable, corroborated by market data or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the extent possible.

A three-tier hierarchy has been established that classifies fair value amounts recognized in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2 fair value measures) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3 fair value measures). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy. The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

- *Level 1 fair value measures*. Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur with sufficient frequency so as to provide pricing information on an ongoing basis (e.g., transactions on the New York Mercantile Exchange ("NYMEX")). Our Level 1 fair values consist of financial assets and liabilities such as exchange-traded commodity derivative instruments.

- *Level 2 fair value measures*. Level 2 fair values are based on pricing inputs other than quoted prices in active markets (a Level 1 fair value measure) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, the time value of money, volatility factors, current market and contractual prices for the underlying instruments and other relevant economic measures. Substantially all of these assumptions (i) are observable in the marketplace throughout the full term of the instrument; (ii) can be derived from observable data; or (iii) are validated by inputs other than quoted prices (e.g., interest rate and yield curves at commonly quoted intervals). Our Level 2 fair values primarily consist of commodity derivative instruments such as forwards, swaps and other instruments transacted on an exchange or over-the-counter and interest rate derivative instruments. The fair values of these derivative instruments are based on observable price quotes for similar products and locations. The fair value of our interest rate derivatives are determined using financial models that incorporate third-party yield curves for the same period as the future interest rate swap settlements.

- *Level 3 fair value measures*. Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect management's ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available to us in the circumstances, which might include our internally developed forecasts. Level 3 inputs are typically used in connection with internally developed valuation methodologies where we make our best estimate of fair value. Valuations using Level 3 inputs are reviewed and approved by members of senior management.

  With regards to commodity derivatives, our Level 3 fair values primarily consist of the following commodity derivative instruments used to hedge various inventories and transportation capacities: (i) NGL-based contracts with terms greater than one year; (ii) crude, natural gas and refined products-based contracts with terms greater than 36 months; (iii) over-the-counter options; and (iv) exchange traded options with terms greater than one year. In addition, we often rely on price quotes from reputable brokers who publish price quotes on certain products and compare these prices to other reputable brokers for the same products in the same markets whenever possible. These prices, when combined with data from our commodity derivative instruments, are used in our models to determine the fair value of such instruments.

Our nonrecurring fair value estimates are generally based on the income approach to fair value and reflect various Level 3 inputs. In many cases, there are no active markets (a Level 1 fair value measure) to rely on or other similar recent transactions (a Level 2 fair value measure) to compare to. Our nonrecurring fair value estimates often include management's expectations of the residual market values for the underlying assets based on their knowledge and experience in the industry (a Level 3 fair value measure). Other examples of Level 3 inputs used in the valuation models include anticipated gross operating margins, throughput or processing volumes, utilization factors, sustaining capital expenditures, discount rates and business growth rates. When probability weights are used in cash flow modeling, the weights are generally obtained from management personnel having oversight responsibilities for the assets being tested.

Impairment Testing

The following table summarizes our asset impairment charges by type as presented on our Statements of Consolidated Cash Flows for the years indicated:

	For the Year Ended December 31,		
	2020	2019	2018
Impairment charges reflected in operating costs and expenses:			
Property, plant and equipment (see Note 4)	$ 589.8	$ 51.0	$ 46.8
Investment in unconsolidated affiliate (see Note 5)	–	76.4	–
Goodwill (see Note 6)	296.3	–	–
Other (1)	4.5	5.3	3.7
Total asset impairment charges in operating costs and expenses	890.6	132.7	50.5
Other property, plant and equipment impairment charges (2)	–	0.1	–
Total asset impairment charges	$ 890.6	$ 132.8	$ 50.5

(1) Primarily represents the write-down of surplus materials classified as current assets and intangible assets other than goodwill.
(2) Amounts presented are reflected in general and administrative costs.

Asset impairment charges related to operations are a component of "Third party and other costs" within the "Operating costs and expenses" section of our Statements of Consolidated Operations.

The following information describes our accounting policies regarding impairment testing for major asset categories:

- *Impairment Testing for Long-Lived Assets.* Long-lived assets, which consist of intangible assets with finite lives and property, plant and equipment, are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the asset. If the asset's carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset's carrying value over its estimated fair value is recorded. Fair value is defined as the price that would be received to sell an asset or be paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques. See Note 4 for information regarding impairment charges attributable to property, plant and equipment.

- *Impairment Testing for Investments in Unconsolidated Affiliates.* We evaluate our equity method investments for impairment when there are events or changes in circumstances that indicate there is a potential loss in value of the investment attributable to an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the entity and/or long-term negative changes in the entity's industry. In the event we determine that the value of an investment is not recoverable due to an other than temporary decline, we record a non-cash impairment charge to adjust the carrying value of the investment to its estimated fair value. See Note 5 for information regarding an impairment charge attributable to our investments in unconsolidated affiliates in 2019.

- *Impairment Testing for Goodwill.* Goodwill, which represents the cost of an acquired business in excess of the fair value of its net assets at the acquisition date, is subject to annual impairment testing in the fourth quarter of each year or when events or changes in circumstances indicate that the carrying amount of the goodwill may not be recoverable. We test goodwill for impairment at the reporting unit (or operating segment) level following guidance in ASU 2017-04, "Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment," the provisions of which we adopted on January 1, 2020. Goodwill impairment charges represent the amount by which a reporting unit's carrying value (including its respective goodwill) exceeds its fair value, not to exceed the carrying amount of the reporting unit's goodwill.

  We determine the fair value of each reporting unit using accepted valuation techniques, primarily through the use of discounted cash flows (i.e., an income approach to fair value) supplemented by market-based assessments, if available. The estimated fair values of our reporting units incorporate assumptions regarding the future economic prospects of the assets and operations that comprise each reporting unit including: (i) discrete financial forecasts for the assets comprising the reporting unit, which, in turn, rely on management's estimates of long-term operating margins, throughput volumes, capital investments and similar factors; (ii) long-term growth rates for the reporting unit's cash flows beyond the discrete forecast period; and (iii) appropriate discount rates. The fair value estimates are based on Level 3 inputs of the fair value hierarchy. We believe that the assumptions we use in estimating reporting unit fair values are consistent with those that market participants would use in their fair value estimation process. However, due to uncertainties in the estimation process and volatility in the supply and demand for hydrocarbons and similar risk factors, actual results could differ significantly from our estimates. See Note 6 for information regarding an impairment charge attributable to goodwill in 2020.

We are closely monitoring the recoverability of our long-lived assets, investments in unconsolidated affiliates and goodwill in light of the adverse economic effects of the coronavirus disease 2019 ("COVID-19") pandemic. If the adverse economic impacts of the pandemic persist for longer periods than currently expected, these developments could result in the recognition of additional non-cash impairment charges in the future.

Inventories

Inventories primarily consist of NGLs, petrochemicals, refined products, crude oil and natural gas volumes that are valued at the lower of cost or net realizable value. We capitalize, as a cost of inventory, shipping and handling charges (e.g., pipeline transportation and storage fees) and other related costs associated with purchased volumes. As volumes are sold and delivered out of inventory, the cost of these volumes (including freight-in charges that have been capitalized as part of inventory cost) are charged to operating costs and expenses. Shipping and handling fees associated with products we sell and deliver to customers are charged to operating costs and expenses as incurred. See Note 3 for additional information regarding our inventories.

Leases

In February 2016, the FASB issued Accounting Standards Codification ("ASC") 842, *Leases*, which requires substantially all leases be recorded on the balance sheet. We adopted the new standard on January 1, 2019 and applied it to (i) all new leases entered into after January 1, 2019 and (ii) all existing lease contracts as of January 1, 2019. ASC 842 supersedes existing lease accounting guidance found under ASC 840, *Leases*.

The new standard introduces two lessee accounting models, which results in a lease being classified as either a "finance" or "operating" lease based on whether the lessee effectively obtains control of the underlying asset during the lease term. A lease would be classified as a finance lease if it meets one of five classification criteria, four of which are generally consistent with ASC 840 lease accounting guidance. By default, a lease that does not meet the criteria to be classified as a finance lease will be deemed an operating lease. Regardless of classification, the initial measurement of both lease types will result in the balance sheet recognition of a right-of-use ("ROU") asset (representing a company's right to use the underlying asset for a specified period of time) and a corresponding lease liability. The lease liability will be recognized at the present value of the future lease payments, and the ROU asset will equal the lease liability adjusted for any prepaid rent, lease incentives provided by the lessor, and any indirect costs.

The subsequent measurement of each type of lease varies. For finance leases, a lessee will amortize the ROU asset (generally on a straight-line basis in a manner similar to depreciation) and accrete the lease liability (as a component of interest expense) using the effective interest method. Operating leases will result in the recognition of a single lease expense amount that is recorded on a straight-line basis.

ASC 842 resulted in changes to the way our operating leases are recorded, presented and disclosed in our consolidated financial statements. Upon adoption of ASC 842 on January 1, 2019, we recognized a $246.1 million ROU asset and a corresponding lease liability based on the present value of then existing long-term operating lease obligations. In addition, we elected to apply several practical expedients and made accounting policy elections upon adoption of ASC 842 including:

- We do not recognize ROU assets and lease liabilities for short-term leases and instead record them in a manner similar to operating leases under legacy lease accounting guidelines. A short term lease is one with a maximum lease term of 12 months or less and does not include a purchase option the lessee is reasonably certain to exercise.

- We did not reassess whether any expired or existing contracts as of January 1, 2019 contained leases or the lease classification for any such existing or expired leases.

- The impact of adopting ASC 842 was prospective beginning January 1, 2019. We did not recast prior periods presented in our consolidated financial statements to reflect the new lease accounting guidance.

- We combine lease and nonlease components relating to our office and warehouse leases, as applicable.

See Note 17 for our disclosures regarding operating lease obligations.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized, and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in results of operations for the respective period.

We capitalize interest costs incurred on funds used to construct property, plant and equipment while the asset is in its construction phase. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset's estimated useful life as a component of depreciation expense. When capitalized interest is recorded, it reduces interest expense from what it would be otherwise.

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. With respect to midstream energy assets such as natural gas gathering systems that are reliant upon a specific natural resource basin for throughput volumes, the anticipated useful economic life of such assets may be limited by the estimated life of the associated natural resource basin from which the assets derive benefit. Our forecast of the remaining life for the applicable resource basins is based on several factors, including information published by the U.S. Energy Information Administration. Where appropriate, we use other depreciation methods (generally accelerated) for tax purposes.

Leasehold improvements are recorded as a component of property, plant and equipment. The cost of leasehold improvements is charged to earnings using the straight-line method over the shorter of (i) the remaining lease term or (ii) the estimated useful lives of the improvements. We consider renewal terms that are deemed reasonably assured when estimating remaining lease terms.

Our assumptions regarding the useful economic lives and residual values of our assets may change in response to new facts and circumstances, which would prospectively impact our depreciation expense amounts. Examples of such circumstances include, but are not limited to: (i) changes in laws and regulations that limit the estimated economic life of an asset; (ii) changes in technology that render an asset obsolete; (iii) changes in expected salvage values or (iv) significant changes in the forecast life of the applicable resource basins, if any.

Certain of our plant facilities undergo periodic planned outages for major maintenance activities. The method of accounting for these activities depends on whether the plant utilizes either a distillation-based or reaction-based process. Our natural gas processing plants, NGL fractionators, deisobutanizers, propylene splitters and similar facilities utilize thermal distillation processes to separate hydrocarbons into more useful components. Our reaction-based plants, which primarily include our PDH, isomerization and octane enhancement facilities, utilize catalysts to facilitate chemical reactions that convert lower value hydrocarbons into higher value products. We use the expense-as-incurred method to account for the planned major maintenance activities of distillation-based plants. For reaction-based plants, we use the deferral method when accounting for major maintenance activities. Under the deferral method, major maintenance costs are capitalized and amortized over the period until the next major overhaul project. We adopted the deferral method for our reaction-based plants in November 2020. Historically, the costs of major maintenance activities attributable to our reaction-based facilities, principally our octane enhancement assets, were not material to our consolidated financial statements.

With regard to the planned major maintenance activities of our marine transportation assets and underground storage caverns, we continue to use the deferral method to account for such costs.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. ARO amounts are measured at their estimated fair value using expected present value techniques. Over time, the ARO liability is accreted to its present value (through accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-lived asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts.

See Note 4 for additional information regarding our property, plant and equipment and AROs.

Revenues

Substantially all of our revenues are accounted for under ASC 606, *Revenue from Contracts with Customers,* however, to a limited extent, some revenues are accounted for under other guidance such as ASC 842, *Leases,* ASC 845, *Nonmonetary Transactions,* or ASC 815, *Derivatives and Hedging Activities*.

The core principle of ASC 606 is that a company should recognize revenue in a manner that fairly depicts the transfer of goods or services to customers in amounts that reflect the consideration the company expects to receive for those goods or services. We apply this core principle by following five key steps outlined in ASC 606: (i) identify the contract; (ii) identify the performance obligations in the contract; (iii) determine the transaction price; (iv) allocate the transaction price to the performance obligations in the contract; and (v) recognize revenue when (or as) the performance obligation is satisfied. Each of these steps involves management judgment and an analysis of the contract's material terms and conditions.

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

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

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

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

Customers may contribute funds to us to help offset the construction costs related to pipeline construction activities and production well tie-ins. These receipts are recognized as additional service revenues over the term of the associated midstream services provided to the customer.

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

See Note 9 regarding our revenue disclosures.

Note 3. Inventories

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

	December 31,	
	2020	2019
NGLs	$ 1,888.1	$ 1,094.9
Petrochemicals and refined products	642.6	311.5
Crude oil	758.1	674.2
Natural gas	14.7	10.8
Total	$ 3,303.5	$ 2,091.4

Inventories of NGLs, refined products and crude oil increased since December 31, 2019 primarily due to the use of working capital in connection with our marketing activities.

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to outright purchases from third parties for cash), these volumes are valued at market-based prices during the month in which they are acquired.

The following table presents our total cost of sales amounts and lower of cost or net realizable value adjustments for the years indicated:

	For the Year Ended December 31,		
	2020	2019	2018
Cost of sales (1)	$ 16,723.2	$ 22,065.8	$ 26,789.8
Lower of cost or net realizable value adjustments recognized in cost of sales	60.2	22.7	11.5

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

Due to fluctuating commodity prices, we recognize lower of cost or net realizable value adjustments when the carrying value of our available-for-sale inventories exceeds their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized. To the extent our commodity hedging strategies address inventory-related price risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 14 for a description of our commodity hedging activities.

Note 4. Property, Plant and Equipment

The historical costs of our property, plant and equipment and related accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	December 31, 2020	December 31, 2019
Plants, pipelines and facilities (1)	3-45 (5)	$ 49,972.8	$ 47,201.2
Underground and other storage facilities (2)	5-40 (6)	4,207.5	3,965.5
Transportation equipment (3)	3-10	204.9	198.9
Marine vessels (4)	15-30	932.7	905.9
Land		371.9	372.3
Construction in progress		1,807.7	2,641.2
Total		57,497.5	55,285.0
Less accumulated depreciation		15,584.7	13,681.6
Property, plant and equipment, net		$ 41,912.8	$ 41,603.4

(1) Plants, pipelines and facilities include processing plants; NGL, natural gas, crude oil and petrochemical and refined products pipelines; terminal loading and unloading facilities; buildings; office furniture and equipment; laboratory and shop equipment and related assets.
(2) Underground and other storage facilities include underground product storage caverns; above ground storage tanks; water wells and related assets.
(3) Transportation equipment includes tractor-trailer tank trucks and other vehicles and similar assets used in our operations.
(4) Marine vessels include tow boats, barges and related equipment used in our marine transportation business.
(5) In general, the estimated useful lives of major assets within this category are: processing plants, 20-35 years; pipelines and related equipment, 5-45 years; terminal facilities, 10-35 years; buildings, 20-40 years; office furniture and equipment, 3-20 years; and laboratory and shop equipment, 5-35 years.
(6) In general, the estimated useful lives of assets within this category are: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

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

	For the Year Ended December 31,		
	2020	2019	2018
Depreciation expense (1)	$ 1,681.9	$ 1,562.6	$ 1,436.2
Capitalized interest (2)	115.0	143.8	147.9

(1) Depreciation expense is a component of "Costs and expenses" as presented on our Statements of Consolidated Operations.
(2) Capitalized interest is a component of "Interest expense" as presented on our Statements of Consolidated Operations.

Asset Retirement Obligations

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

Property, plant and equipment at December 31, 2020 and 2019 includes $69.7 million and $69.6 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents information regarding our AROs for the years indicated:

	For the Year Ended December 31,		
	2020	2019	2018
ARO liability beginning balance	$ 132.1	$ 126.3	$ 86.7
Liabilities incurred	4.6	5.0	24.4
Liabilities settled	(1.5)	(2.3)	(2.5)
Revisions in estimated cash flows	6.1	(4.8)	11.5
Accretion expense	8.2	7.9	6.2
ARO liability ending balance	$ 149.5	$ 132.1	$ 126.3

The following table presents our forecast of ARO-related accretion expense for the years indicated:

2021	2022	2023	2024	2025
$ 8.6	$ 9.1	$ 9.6	$ 10.3	$ 10.9

Impairments of Property, Plant and Equipment

The following table presents our non-cash asset impairment charges involving property, plant and equipment by business segment for the years indicated:

	For the Year Ended December 31,		
	2020	2019	2018
NGL Pipelines & Services:			
South Texas natural gas processing plants	$ 86.9	$ 15.6	
Other	121.2	23.5	$ 18.6
Crude Oil Pipelines & Services:			
Cancellation of Midland-to-ECHO 4 project	42.2		
Other	3.3	2.6	11.2
Natural Gas Pipelines & Services:			
South Texas natural gas gathering pipelines	37.8		
Other	5.5	4.8	13.9
Petrochemical & Refined Products Services:			
Marine transportation business	252.1		
Other	40.8	4.6	3.1
Total impairment charges for property, plant and equipment	$ 589.8	$ 51.1	$ 46.8

The following information summarizes our significant asset impairment charges involving property, plant and equipment that were recognized during the year ended December 31, 2020:

- In December 2020, we evaluated our marine transportation business for impairment due to a lower demand outlook for such services. As a result of our review, we recognized an impairment charge of $256.7 million, which reduced the carrying value of this asset group to its estimated fair value of $410.0 million at December 31, 2020. The impairment charge reduced property, plant and equipment by $252.1 million and intangible assets by $4.6 million. Our marine transportation assets, which consist of 65 tow boats, 160 tank barges and shipyard and repair facilities, serve refinery and storage terminal customers along the Mississippi River, the intracoastal waterway between Texas and Florida, and the Tennessee-Tombigbee waterway system.

- In December 2020, we evaluated certain of our natural gas gathering and processing assets in South Texas for impairment due to a lower production outlook. As a result of our review, we recognized an aggregate impairment charge of $125.7 million, which reduced the total carrying value of these assets to their estimated fair value of $21.3 million at December 31, 2020. The impairment charge reduced property, plant and equipment by $124.7 million and intangible assets by $1.0 million. The natural gas assets impacted by this review were our Armstrong, Gilmore, Shilling and Indian Springs natural gas processing facilities and our Indian Springs and Big Thicket Gathering Systems.

- In September 2020, we recognized $42.2 million of impairment expense due to our cancellation of the Midland-to-ECHO 4 pipeline construction project. In connection with the cancellation, we reclassified $311.7 million of pipe and related items that were purchased for the project from construction in progress to long-term spare parts, where they will be held for future use. Long-term spare parts is a component of "Other assets" as presented on our Consolidated Balance Sheet. While being held as long-term spare parts, these assets are depreciated over their expected useful lives as spare parts.

- The remainder of our impairment charges for 2020 (i.e., those classified as "Other" in the preceding table) are attributable to the complete write-off of assets that are no longer expected to be used or constructed.

For information regarding our non-recurring fair value estimates for the marine transportation business and our South Texas natural gas gathering and processing assets, see Note 14.

Note 5. Investments in Unconsolidated Affiliates

The following table presents our investments in unconsolidated affiliates by business segment at the dates indicated. We account for these investments using the equity method.

	Ownership Interest at December 31, 2020	December 31, 2020	December 31, 2019
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C. ("VESCO")	13.1%	$ 23.4	$ 23.2
K/D/S Promix, L.L.C. ("Promix")	50%	23.0	25.7
Baton Rouge Fractionators LLC ("BRF")	32.2%	13.8	15.6
Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu")	50%	31.6	33.1
Texas Express Pipeline LLC ("Texas Express")	35%	342.8	358.1
Texas Express Gathering LLC ("TEG")	45%	37.7	41.1
Front Range Pipeline LLC ("Front Range")	33.3%	199.3	207.0
Crude Oil Pipelines & Services:			
Seaway Crude Holdings LLC ("Seaway")	50%	1,224.0	1,353.1
Eagle Ford Pipeline LLC ("Eagle Ford Crude Oil Pipeline")	50%	376.8	386.5
Eagle Ford Terminals Corpus Christi LLC ("Eagle Ford Corpus Christi")	50%	122.9	126.9
Natural Gas Pipelines & Services:			
White River Hub, LLC ("White River Hub")	50%	18.2	19.1
Old Ocean Pipeline, LLC ("Old Ocean")	50%	13.2	8.2
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator LLC ("BRPC")	30%	1.6	2.0
Transport 4, LLC ("Transport 4")	25%	0.9	0.6
Total		$ 2,429.2	$ 2,600.2

NGL Pipelines & Services

The principal business activity of each investee included in our NGL Pipelines & Services segment is described as follows:

- *VESCO* owns the Venice natural gas processing facility and a related gathering system located in south Louisiana.

- *Promix* owns an NGL fractionation facility and a related gathering system located in south Louisiana.

- *BRF* owns an NGL fractionation facility located in south Louisiana.

- *Skelly-Belvieu* owns a pipeline that transports mixed NGLs from Skellytown, Texas to Mont Belvieu, Texas.

- *Texas Express* owns an NGL pipeline that extends from Skellytown to our Mont Belvieu NGL fractionation and storage complex. Mixed NGLs from the Rocky Mountains, Permian Basin and Mid-Continent regions are delivered to the Texas Express Pipeline via an interconnect with our Mid-America Pipeline System near Skellytown. In addition, mixed NGLs from the Denver-Julesburg ("DJ") Basin in Colorado are delivered to the Texas Express Pipeline via an interconnect with the Front Range Pipeline near Skellytown. The Texas Express Pipeline is also used to transport mixed NGLs gathered by TEG to Mont Belvieu.

- *TEG* owns two NGL gathering systems that deliver mixed NGLs to the Texas Express Pipeline.

- *Front Range* owns an NGL pipeline that transports mixed NGLs from natural gas processing facilities located in the DJ Basin to an interconnect with our Texas Express Pipeline and Mid-America Pipeline System and other third party facilities near Skellytown.

Crude Oil Pipelines & Services

The principal business activity of each investee included in our Crude Oil Pipelines & Services segment is described as follows:

- *Seaway* owns a crude oil pipeline system that connects the Cushing, Oklahoma hub, which is a major industry trading hub and price settlement point for West Texas Intermediate on the NYMEX, with markets in Southeast Texas. The Seaway Pipeline is comprised of the Longhaul System, the Freeport System and the Texas City System.

- *Eagle Ford Crude Oil Pipeline* owns a pipeline that transports crude oil and condensate for producers in South Texas. The system originates in Gardendale, Texas and extends to Three Rivers, Texas and further to Corpus Christi, Texas. The system interconnects with our South Texas Crude Oil Pipeline System and a marine terminal owned by Eagle Ford Corpus Christi.

- *Eagle Ford Corpus Christi* owns a marine crude oil terminal located in Corpus Christi, Texas that can load ocean-going vessels with either crude oil or condensate.

Natural Gas Pipelines & Services

The principal business activity of each investee included in our Natural Gas Pipelines & Services segment is described as follows:

- *White River Hub* owns a natural gas hub facility serving producers in the Piceance Basin of northwest Colorado.

- *Old Ocean* owns a natural gas pipeline that extends from near Maypearl, Texas to Sweeny, Texas.

Petrochemical & Refined Products Services

The principal business activity of each investee included in our Petrochemical & Refined Products Services segment is described as follows:

- *BRPC* owns a propylene fractionation facility located in south Louisiana.

- *Transport 4* provides pipeline and terminal logistics services used by our refined products pipelines.

Equity Earnings

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

	For the Year Ended December 31,		
	2020	2019	2018
NGL Pipelines & Services	$ 121.3	$ 114.5	$ 117.0
Crude Oil Pipelines & Services	301.2	449.2	365.4
Natural Gas Pipelines & Services	5.8	6.3	6.8
Petrochemical & Refined Products Services (1)	(2.2)	(7.0)	(9.2)
Total	$ 426.1	$ 563.0	$ 480.0

(1) The losses recorded for this segment are primarily due to protection, maintenance and pipeline integrity costs of the idled Centennial Pipeline, which was purged and filled with nitrogen in 2013.

Impairment of Investment in Unconsolidated Affiliate

In December 2019, we recorded a $76.4 million impairment charge to fully write off our 50% equity method investment in Centennial Pipeline LLC ("Centennial"), which owns the idled Centennial Pipeline and related terminal infrastructure. Due to declines in the viability of potential commercial transactions involving this former refined products pipeline, we concluded that our investment was not recoverable and had no fair value at December 31, 2019. The impairment charge is a component of operating costs and expenses for the year ended December 31, 2019 as presented on our Statements of Consolidated Operations. We continue to own a 50% equity interest in the Centennial Pipeline, which is being maintained in an idled state in accordance with governmental regulations.

Note 6. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	December 31, 2020			December 31, 2019		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 447.8	$ (221.3)	$ 226.5	$ 447.8	$ (206.3)	$ 241.5
Contract-based intangibles	162.6	(55.0)	107.6	162.6	(43.9)	118.7
Segment total	610.4	(276.3)	334.1	610.4	(250.2)	360.2
Crude Oil Pipelines & Services:						
Customer relationship intangibles	2,195.0	(291.6)	1,903.4	2,203.5	(243.5)	1,960.0
Contract-based intangibles	283.1	(249.9)	33.2	276.9	(235.0)	41.9
Segment total	2,478.1	(541.5)	1,936.6	2,480.4	(478.5)	2,001.9
Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,350.3	(512.2)	838.1	1,350.3	(481.6)	868.7
Contract-based intangibles	470.7	(403.8)	66.9	468.0	(395.5)	72.5
Segment total	1,821.0	(916.0)	905.0	1,818.3	(877.1)	941.2
Petrochemical & Refined Products Services:						
Customer relationship intangibles	181.4	(68.3)	113.1	181.4	(57.5)	123.9
Contract-based intangibles	44.9	(24.6)	20.3	46.0	(24.2)	21.8
Segment total	226.3	(92.9)	133.4	227.4	(81.7)	145.7
Total intangible assets	$ 5,135.8	$ (1,826.7)	$ 3,309.1	$ 5,136.5	$ (1,687.5)	$ 3,449.0

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

	For the Year Ended December 31,		
	2020	2019	2018
NGL Pipelines & Services	$ 25.2	$ 31.9	$ 34.7
Crude Oil Pipelines & Services	71.5	92.7	87.8
Natural Gas Pipelines & Services	38.8	41.4	39.1
Petrochemical & Refined Products Services	7.7	8.7	8.7
Total	$ 143.2	$ 174.7	$ 170.3

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

2021	2022	2023	2024	2025
$ 144.5	$ 161.3	$ 169.0	$ 165.1	$ 163.5

<u>Customer relationship intangible assets</u>
Customer relationship intangible assets represent the estimated economic value assigned to commercial relationships acquired in connection with business combinations. Our customer relationship intangible assets are classified as either (i) basin-specific or (ii) general. Basin-specific customer relationships represent access to customers associated with a defined resource basin (e.g., customers using a natural gas gathering system serving a specific production field) and is analogous to having a franchise in a particular area. General customer relationships are associated with customers whose hydrocarbon volumes are not attributable to specific resource basins (e.g. customers at a marine terminal that handles volumes originating from multiple sources).

The estimated fair value of each customer relationship intangible asset was determined at the time of acquisition using a discounted cash flow analysis, which incorporates various assumptions regarding the acquired business. The assumptions may include Level 3 fair value inputs, including long-range cash flow forecasts that extend for the estimated economic life of the hydrocarbon resource base served by the asset network, anticipated service contract renewals, resource base depletion rates and expected customer attrition rates.

The recognition of customer relationships are supported by a variety of factors. In general, midstream infrastructure requires a significant investment, both in terms of initial construction costs and ongoing maintenance, and is generally supported by long-term contracts that establish a customer base. The level of expenditures and regulatory requirements involved in constructing new midstream asset networks can create significant economic barriers to entry that may limit potential competition. Furthermore, efficient, continuous operation of the acquired fixed assets not only supports the commercial relationships existing at the time of the acquisition, but it provides us with opportunities to establish new ones. These factors support the long-term value attributed to our customer relationship intangible assets.

With respect to amortization periods, the duration of a basin-specific customer relationship is limited to the estimated economic life of the associated resource basin. The duration of our other customer relationships is typically limited to the term of the underlying service contracts, including assumed renewals. Amortization expense attributable to customer relationships is recorded in a manner that closely resembles the pattern in which we expect to benefit from such relationships.

At December 31, 2020, the carrying value of our portfolio of customer relationship intangible assets was $3.08 billion, the principal components of which were as follows:

	Weighted Average Remaining Amortization Period	December 31, 2020		
		Gross Value	Accumulated Amortization	Carrying Value
Basin-specific customer relationships:				
EFS Midstream (acquired 2015)	21.4 years	$ 1,409.8	$ (188.1)	$ 1,221.7
State Line and Fairplay (acquired 2010)	26.2 years	895.0	(224.0)	671.0
San Juan Gathering (acquired 2004)	18.8 years	331.3	(245.3)	86.0
General customer relationships:				
Oiltanking (acquired 2014)	23.0 years	1,192.5	(162.6)	1,029.9

- The *EFS Midstream* customer relationships provide us with long-term access to condensate and natural gas producers in the Eagle Ford Shale served by our EFS Midstream System. The EFS Midstream System provides condensate gathering and processing services along with gathering, treating and compression services for associated natural gas.

- The *State Line and Fairplay* customer relationships provide us with long-term access to natural gas producers served by our Haynesville and Fairplay Gathering Systems. 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 East Texas. The Fairplay Gathering System gathers natural gas produced from the Cotton Valley formation in East Texas.

- The *San Juan Gathering* customer relationships provide us with long-term access to natural gas producers in the San Juan Basin served by our San Juan Gathering System.

- The *Oiltanking* customer relationships provide us with long-term access to crude oil and refined products storage and terminal customers served at our Houston Ship Channel and Beaumont, Texas terminals.

In December 2020, we recognized $5.6 million of impairment charges attributable to customer relationship intangible assets in connection with our writedowns of the marine transportation business and certain South Texas natural gas processing and gathering assets (see Note 4).

<u>*Contract-based intangible assets*</u>

Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations. These intangible assets are typically valued using an income approach that incorporate the terms of the agreements. At December 31, 2020, the carrying value of our portfolio of contract-based intangible assets was $228.0 million, the principal components of which were as follows:

	Weighted Average Remaining Amortization Period	December 31, 2020		
		Gross Value	Accumulated Amortization	Carrying Value
Oiltanking customer contracts	3.0 years	$ 293.3	$ (261.7)	$ 31.6
Jonah natural gas gathering agreements	21.0 years	224.4	(175.8)	48.6
Delaware Basin natural gas processing contracts	6.0 years	82.6	(23.7)	58.9

- The *Oiltanking customer contracts* represent the estimated value we assigned to crude oil storage and terminal agreements we acquired in 2014 associated with our Houston and Beaumont marine terminals. Amortization expense attributable to these contracts is recorded using a straight-line approach over the terms of the underlying contracts.

- The *Jonah natural gas gathering agreements* represent the estimated value we assigned to natural gas gathering contracts acquired in 2001 associated with the Jonah Gathering System. Amortization expense attributable to these intangible assets is recorded using a units-of-production method based on gathering volumes.

- The *Delaware Basin natural gas processing contracts* represent the estimated value we assigned to natural gas processing contracts we acquired in March 2018 in connection with our step acquisition of the remaining 50% member interest in Delaware Basin Gas Processing LLC (“Delaware Processing”) (see Note 12). Amortization expense attributable to these contracts is recorded using a straight-line approach over the terms of the underlying contracts.

Impairment of Goodwill

Goodwill represents the cost of acquired businesses in excess of the fair value of their net assets at acquisition. Our goodwill balance was $5.45 billion and $5.75 billion at December 31, 2020 and 2019, respectively.

Based on our most recent goodwill impairment test at December 31, 2020, the estimated fair value of each of our reporting units, with the exception of our natural gas pipelines and services reporting unit (as described below), was at least 10% in excess of its carrying value. The following table presents changes in the carrying amount of goodwill by business segment during the periods indicated:

	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Consolidated Total
Balance at December 31, 2018	$ 2,651.7	$ 1,841.0	$ 296.3	$ 956.2	$ 5,745.2
Balance at December 31, 2019	$ 2,651.7	$ 1,841.0	$ 296.3	$ 956.2	$ 5,745.2
Impairment of goodwill	–	–	(296.3)	–	(296.3)
Balance at December 31, 2020	$ 2,651.7	$ 1,841.0	$ –	$ 956.2	$ 5,448.9

In December 2020, management determined that the carrying value of our natural gas pipelines and services reporting unit exceeded its estimated fair value. This reporting unit, which reflects the operations of our Natural Gas Pipelines & Services business segment, includes our natural gas gathering and transmission pipelines, storage facilities and related marketing activities. The long-term outlook for natural gas production in certain supply basins such as the Rocky Mountains and East Texas is expected to remain lower for longer due to reduced drilling activity. In addition, the decline in pipeline revenues attributable to lower regional natural gas price spreads is expected to adversely impact the future cash flows of our transmission pipelines. These factors, coupled with an increase in the estimated rate of return required for such businesses by market participants, resulted in the fair value of this reporting unit being less than its carrying value at December 31, 2020. The resulting goodwill impairment charge of $296.3 million represents the entire amount of goodwill attributable to this reporting unit and is reflected as a component of operating costs and expenses for the year ended December 31, 2020 as presented on our Statements of Consolidated Operations.

We did not record any goodwill impairment charges during the years ended December 31, 2019 or 2018.

Note 7. Debt Obligations

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

	December 31, 2020	December 31, 2019
EPO senior debt obligations:		
Commercial Paper Notes, variable-rates	$ –	$ 482.0
Senior Notes Q, 5.25% fixed-rate, due January 2020	–	500.0
Senior Notes Y, 5.20% fixed-rate, due September 2020	–	1,000.0
Senior Notes TT, 2.80% fixed-rate, due February 2021	750.0	750.0
Senior Notes RR, 2.85% fixed-rate, due April 2021	575.0	575.0
September 2020 364-Day Revolving Credit Agreement, variable-rate, due September 2021	–	–
Senior Notes VV, 3.50% fixed-rate, due February 2022	750.0	750.0
Senior Notes CC, 4.05% fixed-rate, due February 2022	650.0	650.0
Senior Notes HH, 3.35% fixed-rate, due March 2023	1,250.0	1,250.0
Senior Notes JJ, 3.90% fixed-rate, due February 2024	850.0	850.0
Multi-Year Revolving Credit Agreement, variable-rate, due September 2024	–	–
Senior Notes MM, 3.75% fixed-rate, due February 2025	1,150.0	1,150.0
Senior Notes PP, 3.70% fixed-rate, due February 2026	875.0	875.0
Senior Notes SS, 3.95% fixed-rate, due February 2027	575.0	575.0
Senior Notes WW, 4.15% fixed-rate, due October 2028	1,000.0	1,000.0
Senior Notes YY, 3.125% fixed-rate, due July 2029	1,250.0	1,250.0
Senior Notes AAA, 2.80% fixed-rate, due January 2030	1,250.0	–
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes W, 7.55% fixed-rate, due April 2038	399.6	399.6
Senior Notes R, 6.125% fixed-rate, due October 2039	600.0	600.0
Senior Notes Z, 6.45% fixed-rate, due September 2040	600.0	600.0
Senior Notes BB, 5.95% fixed-rate, due February 2041	750.0	750.0
Senior Notes DD, 5.70% fixed-rate, due February 2042	600.0	600.0
Senior Notes EE, 4.85% fixed-rate, due August 2042	750.0	750.0
Senior Notes GG, 4.45% fixed-rate, due February 2043	1,100.0	1,100.0
Senior Notes II, 4.85% fixed-rate, due March 2044	1,400.0	1,400.0
Senior Notes KK, 5.10% fixed-rate, due February 2045	1,150.0	1,150.0
Senior Notes QQ, 4.90% fixed-rate, due May 2046	975.0	975.0
Senior Notes UU, 4.25% fixed-rate, due February 2048	1,250.0	1,250.0
Senior Notes XX, 4.80% fixed-rate, due February 2049	1,250.0	1,250.0
Senior Notes ZZ, 4.20% fixed-rate, due January 2050	1,250.0	1,250.0
Senior Notes BBB, 3.70% fixed-rate, due January 2051	1,000.0	–
Senior Notes DDD, 3.20% fixed-rate, due February 2052	1,000.0	–
Senior Notes NN, 4.95% fixed-rate, due October 2054	400.0	400.0
Senior Notes CCC, 3.95% fixed rate, due January 2060	1,000.0	–
TEPPCO senior debt obligations:		
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	0.4	0.4
Total principal amount of senior debt obligations	27,500.0	25,232.0
EPO Junior Subordinated Notes C, variable-rate, due June 2067 (1)	232.2	232.2
EPO Junior Subordinated Notes D, fixed/variable-rate, due August 2077 (2)	700.0	700.0
EPO Junior Subordinated Notes E, fixed/variable-rate, due August 2077 (3)	1,000.0	1,000.0
EPO Junior Subordinated Notes F, fixed/variable-rate, due February 2078 (4)	700.0	700.0
TEPPCO Junior Subordinated Notes, variable-rate, due June 2067 (1)	14.2	14.2
Total principal amount of senior and junior debt obligations	30,146.4	27,878.4
Other, non-principal amounts	(280.7)	(253.3)
Less current maturities of debt	(1,325.0)	(1,981.9)
Total long-term debt	$ 28,540.7	$ 25,643.2

(1) Variable rate is reset quarterly and based on 3-month London Interbank Offered Rate ("LIBOR") plus 2.778%.

(2) Fixed rate of 4.875% through August 15, 2022; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 2.986%.

(3) Fixed rate of 5.250% through August 15, 2027; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 3.033%.

(4) Fixed rate of 5.375% through February 14, 2028; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 2.57%.

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

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt during the year ended December 31, 2020:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
Commercial Paper Notes	1.78% to 2.08%	1.86%
EPO Junior Subordinated Notes C and TEPPCO Junior Subordinated Notes	3.00% to 4.68%	3.66%

Amounts borrowed under EPO's 364-Day and Multi-Year Revolving Credit Agreements bear interest, at its election, equal to: (i) LIBOR, plus an additional variable spread; or (ii) an alternate base rate, which is the greater of (a) the Prime Rate in effect on such day, (b) the Federal Funds Effective Rate in effect on such day plus 0.5%, or (c) the LIBO Market Index Rate in effect on such day plus 1% and a variable spread. The applicable spreads are determined based on EPO's debt ratings.

In July 2017, the Financial Conduct Authority in the U.K. announced a desire to phase out LIBOR as a benchmark by the end of June 2023. Financial industry working groups are developing replacement rates and methodologies to transition existing agreements that depend on LIBOR as a reference rate. We currently do not expect the transition from LIBOR to have a material impact on us.

The following table presents the scheduled maturities of principal amounts of EPO's consolidated debt obligations at December 31, 2020 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt					
	Total	2021	2022	2023	2024	2025	Thereafter
Senior Notes	$ 27,500.0	$ 1,325.0	$ 1,400.0	$ 1,250.0	$ 850.0	$ 1,150.0	$ 21,525.0
Junior Subordinated Notes	2,646.4	–	–	–	–	–	2,646.4
Total	$ 30,146.4	$ 1,325.0	$ 1,400.0	$ 1,250.0	$ 850.0	$ 1,150.0	$ 24,171.4

In February 2021, EPO notified its trustee and paying agent to redeem all of the $575.0 million outstanding principal amount of its Senior Notes RR effective as of March 15, 2021 (one month prior to their scheduled maturity in April 2021). These notes are redeemable at EPO's election at par (i.e., at a redemption price equal to the outstanding principal amount of such notes to be redeemed, plus accrued and unpaid interest thereon). On a short term basis, the redemption of EPO's Senior Notes RR is expected to be made using proceeds from the issuance of short term notes under EPO's commercial paper program.

EPO Debt Obligations

Commercial Paper Notes

EPO maintains a commercial paper program under which it may issue (and have outstanding at any time) up to $3.0 billion in aggregate principal amount of short-term notes. As a back-stop to the program, we intend to maintain a minimum available borrowing capacity under EPO's Multi-Year Revolving Credit Agreement equal to the aggregate amount outstanding under our commercial paper notes. All commercial paper notes issued under the program are senior unsecured obligations of EPO that are unconditionally guaranteed by the Partnership. As of December 31, 2020, EPO had no short-term notes outstanding under its commercial paper program.

364-Day Revolving Credit Agreements

In September 2020, EPO entered into a new 364-Day Revolving Credit Agreement (the "September 2020 364-Day Revolving Credit Agreement") that replaced its September 2019 364-Day Revolving Credit Agreement. Under the terms of the September 2020 364-Day Revolving Credit Agreement, EPO may borrow up to $1.5 billion (which may be increased by up to $200 million to $1.7 billion at EPO's election, provided certain conditions are met) at a variable interest rate for a term of up to 364 days, subject to the terms and conditions set forth therein. The September 2020 364-Day Revolving Credit Agreement matures in September 2021. To the extent that principal amounts are outstanding at the maturity date, EPO may elect to have the entire principal balance then outstanding continued as non-revolving term loans for a period of one additional year, payable in September 2022. Borrowings under the September 2020 364-Day Revolving Credit Agreement may be used for working capital, capital expenditures, acquisitions and general company purposes.

The September 2020 364-Day Revolving Credit Agreement contains customary representations, warranties, covenants (affirmative and negative) and events of default, the occurrence of which would permit the lenders to accelerate the maturity date of any amounts borrowed under this credit agreement. The September 2020 364-Day Revolving Credit Agreement also restricts EPO's ability to pay cash distributions to the Partnership, if an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid or would result therefrom.

EPO's obligations under the September 2020 364-Day Revolving Credit Agreement are not secured by any collateral; however, they are guaranteed by the Partnership.

Multi-Year Revolving Credit Agreement
EPO has entered into a multi-year revolving credit agreement (as amended, the "Multi-Year Revolving Credit Agreement") that provides for a borrowing capacity of $3.5 billion, which may be increased by up to $500 million to $4.0 billion at EPO's election provided certain conditions are met, with a maturity date of September 10, 2024. The maturity date may be extended at EPO's request by up to two years, with the consent of required lenders as set forth under the credit agreement. Borrowings under the Multi-Year Revolving Credit Agreement may be used for working capital, capital expenditures, acquisitions and general company purposes.

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

EPO's obligations under the Multi-Year Revolving Credit Agreement are not secured by any collateral; however, they are guaranteed by the Partnership.

Senior Notes
EPO's fixed-rate senior notes are unsecured obligations of EPO that rank equal with its existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. EPO's senior notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict its ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions. In total, EPO issued $4.25 billion, $2.5 billion and $5.0 billion of senior notes during the years ended December 31, 2020, 2019 and 2018, respectively.

In January 2020, EPO issued $3.0 billion aggregate principal amount of senior notes comprised of (i) $1.0 billion principal amount of senior notes due January 2030 ("Senior Notes AAA"), (ii) $1.0 billion principal amount of senior notes due January 2051 ("Senior Notes BBB") and (iii) $1.0 billion principal amount of senior notes due January 2060 ("Senior Notes CCC"). Senior Notes AAA were issued at 99.921% of their principal amount and have a fixed rate of interest of 2.80% per year. Senior Notes BBB were issued at 99.413% of their principal amount and have a fixed rate of interest of 3.70% per year. Senior Notes CCC were issued at 99.360% of their principal amount and have a fixed rate of interest of 3.95% per year. Net proceeds from the January 2020 senior notes offering were used by EPO for the repayment of $500.0 million principal amount of its Senior Notes Q that matured in January 2020, the repayment of amounts outstanding under its commercial paper program and for general company purposes. In addition, net proceeds from this offering were used by EPO for the repayment of $1.0 billion principal amount of its Senior Notes Y that matured in September 2020.

In August 2020, EPO issued $1.0 billion in principal amount of senior notes due February 2052 ("Senior Notes DDD") and $250.0 million in principal amount of reopened Senior Notes AAA. The reopened Senior Notes AAA form a single series with the original notes of that series, trade under the same CUSIP number, and have the same terms as to status, redemption or otherwise as the original notes of that series. The reopened Senior Notes AAA were issued at 107.211% of their principal amount and have a fixed rate of interest of 2.80% per year. Senior Notes DDD were issued at 99.233% of their principal amount and have a fixed rate of interest of 3.20% per year. Net proceeds from the issuance of these senior notes were used for general company purposes, including for growth capital investments, and to repay a portion of the $750.0 million in principal amount of Senior Notes TT that matured in February 2021.

EPO's senior notes are unconditionally guaranteed on an unsecured and unsubordinated basis by the Partnership.

EPO Junior Subordinated Notes

EPO's payment obligations under its junior subordinated notes ("junior notes") are subordinated to all of its current and future senior indebtedness. The indenture agreement governing the junior notes allows EPO to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. Subject to certain exceptions, during any period in which interest payments are deferred, neither the Partnership nor EPO can declare or make any distributions on any of our respective equity securities or make any payments on indebtedness or other obligations that rank equal with or are subordinate to the junior notes. Each series of EPO's junior notes rank equal with each other and generally are not redeemable by EPO while such notes bear interest at a fixed annual rate. EPO issued $700.0 million of junior notes during the year ended December 31, 2018.

In connection with the issuance of EPO's Junior Subordinated Notes C, EPO entered into a Replacement Capital Covenant in favor of covered debt holders (as defined in the underlying documents) pursuant to which EPO agreed, for the benefit of such debt holders, that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made using proceeds from the issuance of certain securities.

EPO's junior notes are unconditionally guaranteed on an unsecured and subordinated basis by the Partnership.

EPO repurchased and retired $24.2 million in principal amount of its Junior Subordinated Notes C in 2019. A $1.5 million gain on the extinguishment of these debt obligations is included in "Other, net" on our Statements of Consolidated Operations with respect to the year ended December 31, 2019.

Letters of Credit

At December 31, 2020, EPO had $200.7 million of letters of credit outstanding primarily related to our commodity hedging activities.

Lender Financial Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at December 31, 2020.

Note 8. Capital Accounts

Common Limited Partner Interests

The following table summarizes changes in the number of our common units outstanding since December 31, 2017:

Common units outstanding at December 31, 2017	2,161,089,479
Common unit repurchases under Legacy Buyback Program	(1,236,800)
Common units issued in connection with DRIP and EUPP	19,861,951
Common units issued in connection with the vesting of phantom unit awards, net	2,442,436
Common units issued in connection with employee compensation	1,443,586
Common units issued in connection with land acquisition	1,223,242
Other	45,135
Common units outstanding at December 31, 2018	2,184,869,029
Common unit repurchases under 2019 Buyback Program	(2,909,128)
Common units issued in connection with DRIP and EUPP	2,897,990
Common units issued in connection with the vesting of phantom unit awards, net	2,720,603
Common units issued in connection with employee compensation	1,626,041
Other	21,595
Common units outstanding at December 31, 2019	2,189,226,130
Common units issued to Skyline North Americas, Inc. in connection with settlement of Liquidity Option in March 2020	54,807,352
Treasury units acquired in connection with settlement of the Liquidity Option in March 2020	(54,807,352)
Common unit repurchases under 2019 Buyback Program	(8,978,317)
Common units issued in connection with the vesting of phantom unit awards, net	3,162,095
Common units exchanged for preferred units in September 2020, with the common units received being immediately cancelled	(1,120,588)
Other	19,638
Common units outstanding at December 31, 2020	2,182,308,958

The Partnership's common units represent limited partner interests that give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Seventh Amended and Restated Agreement of Limited Partnership (as amended from time to time, the "Partnership Agreement"). In accordance with the Partnership Agreement, capital accounts are maintained for our limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. federal income tax purposes and are not comparable to the equity balances presented in our consolidated financial statements prepared in accordance with GAAP. Partnership earnings and cash distributions are allocated to holders of our common units in accordance with their respective percentage interests.

Registration Statements
We have a universal shelf registration statement (the "2019 Shelf") on file with the SEC which allows the Partnership and EPO (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. EPO issued $4.25 billion of senior notes during 2020 using the 2019 Shelf (see Note 7).

In addition, the Partnership has a registration statement on file with the SEC covering the issuance of up to $2.54 billion of its common units in amounts, at prices and on terms based on market conditions and other factors at the time of such offerings (referred to as the Partnership's at-the-market ("ATM") program). The Partnership did not issue any common units under its ATM program during the three years ended December 31, 2020. The Partnership's capacity to issue additional common units under the ATM program remains at $2.54 billion as of December 31, 2020.

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

Issuance of Common Units due to Settlement of Liquidity Option in March 2020
In October 2014, we acquired approximately 65.9% of the limited partner interests of Oiltanking Partners, L.P. ("Oiltanking"), all of the member interests of OTLP GP, LLC, the general partner of Oiltanking ("Oiltanking GP"), and the incentive distribution rights held by Oiltanking GP from Oiltanking Holding Americas, Inc. (currently known as OTA Holdings, Inc., "OTA"), a U.S. corporation, as the first step ("Step 1") of a two-step acquisition of Oiltanking. In February 2015, we completed the second step of this transaction consisting of the acquisition of the noncontrolling interests in Oiltanking. In order to fund the equity consideration paid in Step 1 of the Oiltanking acquisition, we issued 54,807,352 common units to OTA on October 1, 2014 in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act"), pursuant to Section 4(a)(2) thereof. We also entered into a put option agreement (the "Liquidity Option Agreement" or "Liquidity Option") with OTA and Marquard & Bahls AG ("M&B"), a German corporation and the ultimate parent company of OTA, in connection with Step 1. Under the Liquidity Option Agreement, we granted M&B the option to sell to the Partnership 100% of the issued and outstanding capital stock of OTA at any time within a 90-day period commencing on February 1, 2020.

On February 25, 2020, the Partnership received notice of M&B's election to exercise its rights under the Liquidity Option Agreement. On March 5, 2020, the Partnership settled its obligations under the Liquidity Option Agreement by issuing 54,807,352 new common units to Skyline North Americas, Inc. ("Skyline," an affiliate of M&B) in exchange for the capital stock of OTA. As a result of the settlement, OTA became a consolidated subsidiary of ours and we indirectly acquired the 54,807,352 Partnership common units owned by OTA and assumed all future income tax obligations of OTA, including its deferred tax liability.

As a result of the Liquidity Option settlement, the partners' equity balance for common units (as presented on our Consolidated Balance Sheet) increased by $1.30 billion, representing the market value of the 54,807,352 Partnership common units issued to Skyline on March 5, 2020 at a closing price of $23.67 per unit. Since OTA did not meet the definition of a business as described in ASC 805, *Business Combinations*, the OTA transaction was accounted for by the Partnership as the reacquisition of common units and the assumption of OTA's related deferred tax liability. In consolidation, we present the common units owned by OTA as treasury units, with their historical cost equal to the $1.30 billion market value of the Partnership common units issued to Skyline. On September 30, 2020, OTA exchanged the common units it holds for preferred units issued by the Partnership. For information regarding the preferred units and exchange transaction, see "Redeemable Preferred Limited Partner Interests" within this Note 8.

The common units issued to Skyline upon settlement of the Liquidity Option constitute "restricted securities" in the meaning of Rule 144 under the Securities Act and may not be resold except pursuant to an effective registration statement or an available exemption under the Securities Act. In connection with the settlement of the Liquidity Option, the Partnership entered into a Registration Rights Agreement (the "Registration Rights Agreement") with Skyline. Pursuant to the Registration Rights Agreement, Skyline has the right to request that the Partnership prepare and file a registration statement to permit and otherwise facilitate the public resale of all or a portion of the Partnership's common units owned by Skyline and its affiliates. The Partnership's obligation to Skyline to effect such transactions is limited to five registration statements and underwritten offerings. In May 2020, the Partnership filed a registration statement on behalf of Skyline for the resale of up to 54,807,352 common units. This registration statement is effective and, in June 2020, the Partnership filed a prospectus supplement to this registration statement that allows Skyline to sell up to $500 million of the Partnership's common units it owns in connection with an "at-the-market" program that it administers. We do not receive any proceeds from such offerings.

Upon settlement of the Liquidity Option on March 5, 2020, the Liquidity Option liability was effectively replaced by the deferred tax liability of OTA as calculated in accordance with ASC 740, *Income Taxes*. See Note 16 for additional information regarding OTA's deferred tax liability. For information regarding the Liquidity Option prior to its settlement, see Note 17.

Common Unit Repurchases Under Buyback Programs
In January 2019, we announced that the Board of Enterprise GP had approved a $2.0 billion multi-year unit buyback program (the "2019 Buyback Program"), which provides the Partnership with an additional method to return capital to investors. The 2019 Buyback Program authorizes the Partnership to repurchase its common units from time to time, including through open market purchases and negotiated transactions. No time limit has been set for completion of the program, and it may be suspended or discontinued at any time.

The Partnership repurchased 8,978,317 common units under the 2019 Buyback Program through open market and private purchases during the year ended December 31, 2020. The total purchase price of these repurchases was $186.3 million including commissions and fees. During the year ended December 31, 2019, the Partnership repurchased 2,909,128 common units under the 2019 Buyback Program for a total purchase price of $81.1 million including commissions and fees. Units repurchased under the 2019 Buyback Program are immediately cancelled upon acquisition. At December 31, 2020, the remaining available capacity under the 2019 Buyback Program was $1.73 billion.

In December 1998, we announced a common unit buyback program whereby we, together with certain affiliates, could repurchase up to 4,000,000 of the Partnership's common units on the open market (the "Legacy Buyback Program"). The Partnership purchased the remaining authorized amount of 1,236,800 common units in December 2018 for $30.8 million. Units repurchased under the Legacy Buyback Program were immediately cancelled upon acquisition.

Common Units Delivered Under DRIP and EUPP
The Partnership has registration statements on file with the SEC in connection with its distribution reinvestment plan ("DRIP") and employee unit purchase plan ("EUPP"). In July 2019, the Partnership announced that, beginning with the quarterly distribution payment paid in August 2019, it would use common units purchased on the open market, rather than issuing new common units, to satisfy its delivery obligations under the DRIP and EUPP. This election is subject to change in future quarters depending on the Partnership's need for equity capital. Agents of the Partnership purchased 6,982,963 common units and 2,801,196 common units on the open market and delivered them to participants in the DRIP and EUPP during the year ended December 31, 2020 and five months ended December 31, 2019, respectively. Apart from $2.4 million and $0.9 million attributable to the plan discount available to all participants in the EUPP during 2020 and 2019, respectively, the funds used to effect these purchases were sourced from the DRIP and EUPP participants. No other Partnership funds were used to satisfy these obligations. We used open market purchases to satisfy DRIP and EUPP reinvestments in connection with the distribution paid on February 11, 2021.

Prior to July 2019, the Partnership satisfied its delivery obligations under the DRIP and EUPP by issuing new common units to participants. An aggregate 2,897,990 common units and 19,861,951 common units were issued to DRIP and EUPP participants during the seven months ended July 31, 2019 and year ended December 31, 2018, respectively. These transactions generated net cash proceeds of $82.2 million in 2019 and $538.4 million in 2018. Privately held affiliates of EPCO reinvested $29 million and $213 million through the DRIP in each of the years ended December 31, 2019 and 2018, respectively (this amount being a component of the net cash proceeds presented for each period).

After taking into account the number of common units delivered under the DRIP through December 31, 2020, we have the capacity to deliver an additional 50,615,246 common units under this plan. Likewise, we have the capacity to deliver an additional 3,318,607 common units under the EUPP.

Common Units Issued in Connection With the Vesting of Phantom Unit Awards
After taking into account tax withholding requirements, the Partnership issued 3,162,095, 2,720,603 and 2,442,436 new common units to employees in connection with the vesting of phantom unit awards during the years ended December 31, 2020, 2019 and 2018, respectively. See Note 13 for information regarding our phantom unit awards.

Common Units Issued in Connection With Employee Compensation
In February 2019 and 2018, certain employees of EPCO received discretionary bonus payments, less any retirement plan deductions and applicable withholding taxes, for work performed on our behalf during the prior fiscal year (e.g., the bonus paid in February 2019 was with respect to the year ended December 31, 2018). The net dollar value of the bonus amounts was remitted to employees through the issuance of an equivalent value of newly issued Partnership common units under EPCO's 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) (referred to as the "2008 Plan").

In February 2019, we issued 1,626,041 common units, which had a value of $45.6 million, in connection with the employee bonus awards. In February 2018, we issued 1,443,586 common units, which had a value of $39.1 million. The compensation expense associated with each bonus award was recognized during the year in which the work was performed.

Common Units Issued in Connection With Land Acquisition
In April 2018, we acquired land in the Houston, Texas area for $85.2 million. The consideration paid consisted of $55.2 million in cash with the balance funded by the issuance of 1,223,242 Partnership common units.

Redeemable Preferred Limited Partner Interests

The following table summarizes changes in the number of our preferred units outstanding during the year ended December 31, 2020:

Original issuance of preferred units on September 30, 2020:	
Units sold to third party purchasers	35,000
Units sold to a related party	15,000
Total preferred units outstanding at September 30, 2020	50,000
Paid-in kind distribution to related party	138
Preferred units outstanding at December 31, 2020	50,138

On September 30, 2020, the Partnership issued and sold an aggregate of 50,000 Series A Cumulative Convertible Preferred Units in a private placement transaction. The preferred units represent a new class of limited partner interests authorized under the Partnership Agreement. The stated value of each preferred unit is $1,000 per unit. The total offering price for the preferred units was $50.0 million, of which $32.5 million was received in cash with the remaining $17.5 million funded through the exchange of 1,120,588 of the Partnership's common units owned by the purchasers. Cash proceeds from the preferred unit offering include $15.0 million received from a privately held affiliate of EPCO for the purchase of 15,000 preferred units. Offering expenses were approximately $1.0 million.

Concurrently, the Partnership exchanged all of the 54,807,352 Partnership common units owned directly by OTA for 855,915 of the Partnership's new preferred units having an equivalent value. The preferred units held by OTA, like the common units OTA held prior to the exchange, are accounted for as treasury units by the Partnership in consolidation. The historical cost of the treasury units did not change as a result of the exchange and remains at the $1.30 billion recognized on March 5, 2020 in connection with settlement of the Liquidity Option.

As described in the Partnership Agreement, key terms of the preferred units include the following:

- With respect to distribution and liquidation rights, the preferred units rank senior to the Partnership's common units. Preferred units held by persons other than the Partnership, its subsidiaries and its affiliates generally will vote on an as-converted basis with the Partnership's common units and have certain class voting rights with respect to certain protective matters.

- Holders of the preferred units are entitled to receive cumulative quarterly distributions at a rate of 7.25% per annum. The Partnership is prohibited from paying distributions on its common units unless full cumulative distributions on the preferred units are paid or set aside for payment. The Partnership may satisfy its obligation to pay distributions to the preferred unitholders through the issuance, in whole or in part, of additional preferred units (referred to as paid-in kind or "PIK" distributions), with the remainder in cash, subject to certain rights of a holder to elect all cash and other conditions as described in the Partnership Agreement. The exchange by OTA of its common units for PIK-eligible preferred units enables the Partnership to more effectively manage its consolidated cash balances.

  In November 2020, the Partnership made its first quarterly distribution to third party and related party preferred unitholders. The distribution was valued at $0.5 million, consisting of PIK distributions of 138 new preferred units and $0.3 million in cash.

- Subject to certain limitations, each preferred unitholder may elect to convert its preferred units on or after September 30, 2025 into a number of the Partnership's common units equal to (a) the number of preferred units to be converted multiplied by (b) the quotient of (i) $1,000 plus any accrued and unpaid distributions per preferred unit, divided by (ii) 92.5% of the volume-weighted average price of the Partnership's common units at the time of conversion (as defined in the underlying agreements). In addition, each preferred unitholder may convert its preferred units into common units if EPO's senior notes cease to have an investment grade rating or a Change of Control (as defined in the Partnership Agreement) occurs, in each case based on the conversion ratio specified in the Partnership Agreement.

- The Partnership may elect to redeem the preferred units for cash, in whole or in part, based on a redemption price outlined in the following schedule, plus any accrued and unpaid distributions at the redemption date:

  - $1,100 per preferred unit from September 30, 2020 through September 29, 2022;
  - $1,070 per preferred unit from September 30, 2022 through September 29, 2024;
  - $1,030 per preferred unit from September 30, 2024 through September 29, 2025;
  - $1,010 per preferred unit from September 30, 2025 through September 29, 2026; and
  - $1,000 per preferred unit on or after September 30, 2026; however,
  - if a Change of Control event occurs prior to September 30, 2026, the redemption price is $1,010 per preferred unit.

  In connection with a redemption at the Partnership's election, the Partnership may convert up to 50% of the preferred units being redeemed into common units (and to pay cash with respect to the remainder), with each such preferred unit being converted on the applicable redemption date into a number of common units equal to (i) the then-applicable preferred unit redemption price divided by (ii) 92.5% of the volume-weighted average price of the Partnership's common units at the time of conversion (as defined in the underlying agreements).

The Partnership has agreed to prepare and file a registration statement that would permit or otherwise facilitate the public resale of any common units resulting from the conversion of the preferred units to common units.

Our Consolidated Balance Sheet at December 31, 2020 presents the capital accounts of the third-party and related party purchasers of the preferred units as mezzanine equity since the terms of the preferred units allow for cash redemption by the holders in a Change of Control event, without regard to the likelihood of such an event. The preferred units held by OTA are presented as treasury units in consolidation since their ultimate disposition remains under the control of the Partnership.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily reflects cumulative gain or loss on derivative instruments designated and qualified as cash flow hedges from inception less gains or losses previously reclassified from accumulated other comprehensive income (loss) into earnings. Gain or loss amounts related to cash flow hedges recorded in accumulated other comprehensive income (loss) are reclassified to earnings in the same period(s) in which the underlying hedged forecasted transactions affect earnings. If it becomes probable that a forecasted transaction will not occur, the related net gain or loss in accumulated other comprehensive income (loss) is immediately reclassified into earnings.

The following tables present the components of accumulated other comprehensive income (loss) as reported on our Consolidated Balance Sheets at the dates indicated:

	Cash Flow Hedges			
	Commodity Derivative Instruments	Interest Rate Derivative Instruments	Other	Total
Accumulated Other Comprehensive Income (Loss), December 31, 2018	$ 152.7	$ (104.8)	$ 3.0	$ 50.9
Other comprehensive income (loss) for period, before reclassifications	44.1	81.4	(0.6)	124.9
Reclassification of losses (gains) to net income during period	(141.7)	37.3	–	(104.4)
Total other comprehensive income (loss) for period	(97.6)	118.7	(0.6)	20.5
Accumulated Other Comprehensive Income (Loss), December 31, 2019	55.1	13.9	2.4	71.4
Other comprehensive income (loss) for period, before reclassifications	124.4	(127.5)	(0.1)	(3.2)
Reclassification of losses (gains) to net income during period	(272.7)	39.3	–	(233.4)
Total other comprehensive income (loss) for period	(148.3)	(88.2)	(0.1)	(236.6)
Accumulated Other Comprehensive Income (Loss), December 31, 2020	$ (93.2)	$ (74.3)	$ 2.3	$ (165.2)

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

		For the Year Ended December 31,	
Losses (gains) on cash flow hedges:	**Location**	**2020**	**2019**
Interest rate derivatives	Interest expense	$ 39.3	$ 37.3
Commodity derivatives	Revenue	(282.6)	(152.4)
Commodity derivatives	Operating costs and expenses	9.9	10.7
Total		$ (233.4)	$ (104.4)

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

Noncontrolling Interests

Noncontrolling interests represent third party ownership interests in our consolidated subsidiaries. The following table presents the components of noncontrolling interests as reported on our Consolidated Balance Sheets at the dates indicated:

	At December 31,	
Consolidated Subsidiary	**2020**	**2019**
Breviloba LLC (“Breviloba”)(1)	$ 480.4	$ 492.9
Whitethorn Pipeline Company LLC (“Whitethorn”)(2)	193.0	198.9
Enterprise Navigator Ethylene Terminal LLC (“ENET”)(3)	142.2	124.3
Other (4)	257.7	247.4
Total noncontrolling interests in consolidated subsidiaries	$ 1,073.3	$ 1,063.5

(1) Altus Midstream Processing LP acquired a noncontrolling 33% equity interest in Breviloba, which owns the Shin Oak NGL Pipeline, in July 2019 for $440.7 million in cash.
(2) An affiliate of Western Gas Partners, LP acquired a noncontrolling 20% equity interest in Whitethorn, which owns the majority of our Midland-to-ECHO 1 pipeline, in June 2018 for $189.6 million in cash.
(3) Navigator Ethylene Terminals LLC owns a noncontrolling 50% equity interest in ENET, which owns our ethylene export terminal located at Morgan’s Point on the Houston Ship Channel.
(4) Primarily represents noncontrolling equity interests in NGL fractionation and pipeline businesses.

Net income attributable to noncontrolling interests was $110.1 million, $95.8 million and $66.1 million for the years ended December 31, 2020, 2019 and 2018, respectively.

Cash Distributions

The following table presents Enterprise’s declared quarterly cash distribution rates per common unit with respect to the quarter indicated. Actual cash distributions are paid by Enterprise within 45 days after the end of each fiscal quarter.

	Quarterly Distribution Per Common Unit	Record Date	Payment Date
2018:			
1st Quarter	$ 0.4275	4/30/2018	5/8/2018
2nd Quarter	$ 0.4300	7/31/2018	8/8/2018
3rd Quarter	$ 0.4325	10/31/2018	11/8/2018
4th Quarter	$ 0.4350	1/31/2019	2/8/2019
2019:			
1st Quarter	$ 0.4375	4/30/2019	5/13/2019
2nd Quarter	$ 0.4400	7/31/2019	8/13/2019
3rd Quarter	$ 0.4425	10/31/2019	11/12/2019
4th Quarter	$ 0.4450	1/31/2020	2/12/2020
2020:			
1st Quarter	$ 0.4450	4/30/2020	5/12/2020
2nd Quarter	$ 0.4450	7/31/2020	8/12/2020
3rd Quarter	$ 0.4450	10/30/2020	11/12/2020
4th Quarter	$ 0.4500	1/29/2021	2/11/2021

On January 7, 2021, we announced that the Board of Enterprise GP declared a quarterly cash distribution of $0.45 per common unit with respect to the fourth quarter of 2020. The quarterly distribution was paid on February 11, 2021 to unitholders of record as of the close of business on January 29, 2021. The total amount paid was $988.8 million, which includes $7.1 million for distribution equivalent rights on phantom unit awards.

Note 9. Revenues

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

	For the Year Ended December 31,		
	2020	2019	2018
NGL Pipelines & Services:			
Sales of NGLs and related products	$ 8,970.7	$ 10,934.3	$ 12,920.9
Segment midstream services:			
Natural gas processing and fractionation	757.3	1,069.9	1,341.0
Transportation	1,036.8	1,054.3	1,007.0
Storage and terminals	412.4	412.2	380.0
Total segment midstream services	2,206.5	2,536.4	2,728.0
Total NGL Pipelines & Services	11,177.2	13,470.7	15,648.9
Crude Oil Pipelines & Services:			
Sales of crude oil	5,410.8	9,007.8	10,001.2
Segment midstream services:			
Transportation	804.9	801.8	676.5
Storage and terminals	473.3	477.7	364.9
Total segment midstream services	1,278.2	1,279.5	1,041.4
Total Crude Oil Pipelines & Services	6,689.0	10,287.3	11,042.6
Natural Gas Pipelines & Services:			
Sales of natural gas	1,530.5	2,075.4	2,411.7
Segment midstream services:			
Transportation	1,022.6	1,094.0	1,042.7
Total segment midstream services	1,022.6	1,094.0	1,042.7
Total Natural Gas Pipelines & Services	2,553.1	3,169.4	3,454.4
Petrochemical & Refined Products Services:			
Sales of petrochemicals and refined products	5,942.6	4,985.2	5,535.4
Segment midstream services:			
Fractionation and isomerization	187.7	166.6	188.3
Transportation, including marine logistics	482.9	539.4	481.8
Storage and terminals	167.2	170.6	182.8
Total segment midstream services	837.8	876.6	852.9
Total Petrochemical & Refined Products Services	6,780.4	5,861.8	6,388.3
Total consolidated revenues	$ 27,199.7	$ 32,789.2	$ 36,534.2

Substantially all of our revenues are derived from contracts with customers as defined within ASC 606. The following information describes the nature of our significant revenue streams by segment and type:

NGL Pipelines & Services

<u>*Sales of NGLs and related products*</u>
NGL marketing activities generate revenues from spot and term sales of NGLs and related products that we take title to through our natural gas processing activities (i.e., our equity NGL production) and open market and long-term contract purchases. Revenue from these sales contracts is recognized when the NGLs are sold and delivered to customers at market-based prices.

<u>*Midstream services*</u>
Natural gas processing utilizes service contracts that 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.

We recognize midstream service revenues in connection with the equity NGLs we receive under commodity-based contracts (once the processing service has been performed and we are entitled to such volumes). The value assigned to this non-cash consideration and related inventory is based on the market value of the equity NGLs at the time the services are performed. As noted previously, we also recognize product sales revenue, along with a corresponding cost of sales, when these NGLs are delivered and sold to downstream customers under NGL marketing contracts.

NGL fractionation generates revenue using fee-based arrangements. These fees are contractually subject to adjustment for changes in certain fractionation expenses (e.g., fuel costs) and are recognized in the period services are provided.

NGL pipeline transportation contracts and tariffs generate revenue based on a fixed fee per gallon multiplied by the volume transported and delivered (or capacity reserved). Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies or contractual arrangements. Under certain agreements, customers are required to ship a minimum volume with a provision that allows the shipper to make-up any volume shortfalls over an agreed-upon period (referred to as "make-up rights"). Revenue attributable to such agreements is initially deferred and subsequently recognized at the earlier of when the deficiency volume is shipped, when the likelihood of the shipper's ability to meet the minimum volume commitment becomes remote, or when the pipeline is otherwise released from its performance obligation.

NGL and related product storage contracts generate revenue from capacity reservations where we collect a fee for reserving storage capacity for customers in our underground storage wells and above-ground storage tanks. Under these agreements, revenue is recognized on a straight-line basis over the reservation period. In addition, we generally charge customers throughput fees based on volumes delivered into and subsequently withdrawn from storage, which are recognized as the service is provided.

NGL import and export terminaling activities generate revenue in the period services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded.

Crude Oil Pipelines & Services

<u>Sales of crude oil</u>
Crude oil marketing activities generate revenues from the sale and delivery of crude oil purchased either directly from producers or on the open market. Revenue from these sales contracts is recognized when crude oil is sold and delivered to customers at market-based prices.

<u>Midstream services</u>
Crude oil transportation contracts and tariffs generate revenue based upon a fixed fee per barrel multiplied by the volume transported and delivered (or capacity reserved). Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies or contractual arrangements. Under certain agreements, customers are required to ship a minimum volume over an agreed-upon period, with make-up rights. Revenue attributable to such agreements is initially deferred and subsequently recognized at the earlier of when the deficiency volume is shipped, when the likelihood of the shipper's ability to meet the minimum volume commitment becomes remote, or when the pipeline is otherwise released from its performance obligation.

Crude oil storage contracts generate revenue from capacity reservations where we collect a fee for reserving storage capacity for customers at our terminals. Under these agreements, revenue is recognized on a straight-line basis over the reservation period. In addition, customers are billed a fee per unit of volume handled at our terminals. Revenue is recognized as the terminaling service is provided.

Natural Gas Pipelines & Services

<u>Sales of natural gas</u>
Natural gas marketing activities generate revenue from the sale and delivery of natural gas purchased from producers, natural gas processing facilities, and on the open market. Revenue from these sales contracts is recognized when natural gas is sold and delivered to customers at market-based prices.

Midstream services

Natural gas transportation contracts generate revenues based on a fee per unit of volume transported multiplied by the volume gathered or delivered. Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies or contractual arrangements. Revenues under transportation contracts are recognized when the volumes are transported and delivered to customers. In addition, certain of our natural gas pipelines offer firm capacity reservation services whereby the shipper pays a contractual fee based on the level of throughput capacity reserved. Revenues are recognized when the firm capacity services are provided to the shipper.

Petrochemical & Refined Products Services

Sales of petrochemicals and refined products

Our petrochemical and refined products marketing activities generate revenue from the sale and delivery of products to customers at market-based prices. The products handled by these marketing groups include polymer grade propylene, octane additives, high purity isobutylene and various refined products.

Midstream services

Propylene fractionation units and butane isomerization facilities generate revenue through fee-based tolling arrangements with customers. Revenue from such agreements is recognized in the period the services are provided.

Petrochemical and refined products transportation contracts generate revenue based upon a fixed fee per volume multiplied by the volume transported and delivered. Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies or contractual arrangements.

Marine transportation contracts generate revenue based on set day rates or a set fee per cargo movement recognized over the transit time of individual tows. Additionally, we record revenue for the costs of fuel and other operating costs that are directly reimbursed by our marine customers.

Refined products storage contracts generate revenue from capacity reservations where we collect a fee for reserving storage capacity for customers at our terminals. Under these agreements, revenue is recognized on a straight-line basis over the reservation period. In addition, customers are billed a fee per unit of volume handled at our terminals. Revenue is recognized as the terminaling service is provided.

Unbilled Revenue and Deferred Revenue

The following table provides information regarding our contract assets and contract liabilities at the dates indicated:

		December 31,	
Contract Asset	**Location**	**2020**	**2019**
Unbilled revenue (current amount)	Prepaid and other current assets	$ 18.8	$ 17.6
Total		$ 18.8	$ 17.6

		December 31,	
Contract Liability	**Location**	**2020**	**2019**
Deferred revenue (current amount)	Other current liabilities	$ 145.3	$ 117.9
Deferred revenue (noncurrent)	Other long-term liabilities	198.2	197.0
Total		$ 343.5	$ 314.9

The following table presents significant changes in our unbilled revenue and deferred revenue balances during the years indicated:

	Unbilled Revenue	Deferred Revenue
Balance at January 1, 2018 (upon adoption of ASC 606)	$ –	$ 224.7
Amount included in opening balance transferred to other accounts during period (1)	–	(90.8)
Amount recorded during period (2)	321.7	432.5
Amounts recorded during period transferred to other accounts (1)	(310.6)	(274.8)
Amount recorded in connection with business combination	2.2	–
Other changes	–	(0.4)
Balance at December 31, 2018	$ 13.3	$ 291.2
Amount included in opening balance transferred to other accounts during period (1)	(13.3)	(126.4)
Amount recorded during period (2)	340.0	539.8
Amounts recorded during period transferred to other accounts (1)	(322.4)	(384.8)
Other changes	–	(4.9)
Balance at December 31, 2019	$ 17.6	$ 314.9
Amount included in opening balance transferred to other accounts during period (1)	(17.6)	(114.5)
Amount recorded during period (2)	323.0	661.2
Amounts recorded during period transferred to other accounts (1)	(304.2)	(496.7)
Other changes	–	(21.4)
Balance at December 31, 2020	$ 18.8	$ 343.5

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

(2) Unbilled revenue represents revenue that has been recognized upon satisfaction of a performance obligation, but cannot be contractually invoiced (or billed) to the customer at the balance sheet date until a future period. Deferred revenue is recorded when payment is received from a customer prior to our satisfaction of the associated performance obligation.

Remaining Performance Obligations

The following table presents estimated fixed future consideration from revenue contracts that contain minimum volume commitments, deficiency and similar fees and the term of the contracts exceeds one year. These amounts represent the revenues we expect to recognize in future periods from these contracts as of December 31, 2020.

For a significant portion of our revenue, we bill customers a contractual rate for the services provided multiplied by the amount of volume handled in a given period. We have the right to invoice the customer in the amount that corresponds directly with the value of our performance completed to date. Therefore, we are not required to disclose information about the variable consideration of remaining performance obligations since we recognize revenue equal to the amount that we have the right to invoice.

Period	Fixed Consideration
One Year Ended December 31, 2021	$ 3,906.4
One Year Ended December 31, 2022	3,492.3
One Year Ended December 31, 2023	3,110.2
One Year Ended December 31, 2024	2,937.3
One Year Ended December 31, 2025	2,636.5
Thereafter	12,912.5
Total	$ 28,995.2

Note 10. Business Segments and Related Information

Segment Overview

Our operations are reported under four business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services and (iv) Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the types of services rendered (or technologies employed) and products produced and/or sold.

Financial information regarding these segments is evaluated regularly by our co-chief operating decision makers in deciding how to allocate resources and in assessing our operating and financial performance. The co-principal executive officers of our general partner have been identified as our chief operating decision makers. While these two officers evaluate results in a number of different ways, the business segment structure is the primary basis for which the allocation of resources and financial results are assessed.

The following information summarizes the assets and operations of each business segment (mileage and other statistics are unaudited):

- Our NGL Pipelines & Services business segment includes our natural gas processing and related NGL marketing activities, NGL pipelines, NGL fractionation facilities, NGL and related product storage facilities, and NGL marine terminals.

- Our Crude Oil Pipelines & Services business segment includes our crude oil pipelines, crude oil storage and marine terminals, and related crude oil marketing activities.

- Our Natural Gas Pipelines & Services business segment includes our natural gas pipeline systems that provide for the gathering, treating and transportation of natural gas. This segment also includes our natural gas marketing activities.

- Our Petrochemical & Refined Products Services business segment includes our (i) propylene production facilities, which include propylene fractionation units and a PDH facility, and related pipelines and marketing activities, (ii) butane isomerization complex and related deisobutanizer ("DIB") operations, (iii) octane enhancement, iBDH and HPIB production facilities, (iv) refined products pipelines, terminals and related marketing activities, (v) an ethylene export terminal and related operations; and (vi) marine transportation business.

Our plants, pipelines and other fixed assets are located in the U.S.

Segment Gross Operating Margin

We evaluate segment performance based on our financial measure of gross operating margin. Gross operating margin is an important performance measure of the core profitability of our operations and forms the basis of our internal financial reporting. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. Gross operating margin is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests. Our calculation of gross operating margin may or may not be comparable to similarly titled measures used by other companies.

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

	For the Year Ended December 31, 2020	2019	2018
Operating income	$ 5,035.1	$ 6,078.7	$ 5,408.6
Adjustments to reconcile operating income to total segment gross operating margin (addition or subtraction indicated by sign):			
Depreciation, amortization and accretion expense in operating costs and expenses	1,961.5	1,848.3	1,687.0
Asset impairment and related charges in operating costs and expenses	890.6	132.7	50.5
Net gains attributable to asset sales in operating costs and expenses	(4.4)	(5.7)	(28.7)
General and administrative costs	219.6	211.7	208.3
Non-refundable payments received from shippers attributable to make-up rights (1)	119.3	47.0	21.5
Subsequent recognition of revenues attributable to make-up rights (2)	(33.6)	(22.9)	(56.2)
Total segment gross operating margin	$ 8,188.1	$ 8,289.8	$ 7,291.0

(1) Since make-up rights entail a future performance obligation by the pipeline to the shipper, these receipts are recorded as deferred revenue for GAAP purposes; however, these receipts are included in gross operating margin in the period of receipt since they are nonrefundable to the shipper.

(2) As deferred revenues attributable to make-up rights are subsequently recognized as revenue under GAAP, gross operating margin must be adjusted to remove such amounts to prevent duplication since the associated non-refundable payments were previously included in gross operating margin.

The results of operations from our liquids pipelines are primarily dependent upon the volumes transported and the associated fees we charge for such transportation services. Typically, pipeline transportation revenue is recognized when volumes are re-delivered to customers. However, under certain pipeline transportation agreements, customers are required to ship a minimum volume over an agreed-upon period. These arrangements may entail the shipper paying a transportation fee based on a minimum volume commitment, with a provision that allows the shipper to make-up any volume shortfalls over the agreed-upon period (referred to as shipper "make-up rights"). Revenue pursuant to such agreements is initially deferred and subsequently recognized under GAAP at the earlier of when the deficiency volume is shipped, when the likelihood of the shipper's ability to meet the minimum volume commitment becomes remote, or when the pipeline is otherwise released from its performance obligation.

However, management includes deferred transportation revenues relating to the "make-up rights" of committed shippers when reviewing the financial results of certain pipelines (Texas Express Pipeline, Front Range Pipeline, ATEX, Aegis Ethane Pipeline and Seaway Pipeline). From an internal (and segment) reporting standpoint, management considers the transportation fees paid by committed shippers on these pipelines, including any non-refundable revenues that may be deferred under GAAP related to make-up rights, to be important in assessing the financial performance of these pipeline assets. Although the adjustments for make-up rights are included in segment gross operating margin, our consolidated revenues do not reflect any deferred revenues until the conditions for recognizing such revenues are met in accordance with GAAP.

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

	For the Year Ended December 31, 2020	2019	2018
Gross operating margin by segment:			
NGL Pipelines & Services	$ 4,182.4	$ 4,069.8	$ 3,830.7
Crude Oil Pipelines & Services	1,997.3	2,087.8	1,511.3
Natural Gas Pipelines & Services	926.6	1,062.6	891.2
Petrochemical & Refined Products Services	1,081.8	1,069.6	1,057.8
Total segment gross operating margin	$ 8,188.1	$ 8,289.8	$ 7,291.0

Summarized Segment Financial Information

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

	Reportable Business Segments					
	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:						
Year ended December 31, 2020	$ 11,170.6	$ 6,668.8	$ 2,543.2	$ 6,780.4	$ –	$ 27,163.0
Year ended December 31, 2019	13,460.8	10,244.6	3,154.7	5,861.8	–	32,721.9
Year ended December 31, 2018	15,630.5	10,968.2	3,439.5	6,388.3	–	36,426.5
Revenues from related parties:						
Year ended December 31, 2020	6.6	20.2	9.9	–	–	36.7
Year ended December 31, 2019	9.9	42.7	14.7	–	–	67.3
Year ended December 31, 2018	18.4	74.4	14.9	–	–	107.7
Intersegment and intrasegment revenues:						
Year ended December 31, 2020	29,010.3	24,531.3	460.1	5,379.4	(59,381.1)	–
Year ended December 31, 2019	20,840.4	34,613.0	624.7	2,481.3	(58,559.4)	–
Year ended December 31, 2018	26,453.6	35,490.4	721.9	2,917.5	(65,583.4)	–
Total revenues:						
Year ended December 31, 2020	40,187.5	31,220.3	3,013.2	12,159.8	(59,381.1)	27,199.7
Year ended December 31, 2019	34,311.1	44,900.3	3,794.1	8,343.1	(58,559.4)	32,789.2
Year ended December 31, 2018	42,102.5	46,533.0	4,176.3	9,305.8	(65,583.4)	36,534.2
Equity in income (loss) of unconsolidated affiliates:						
Year ended December 31, 2020	121.3	301.2	5.8	(2.2)	–	426.1
Year ended December 31, 2019	114.5	449.2	6.3	(7.0)	–	563.0
Year ended December 31, 2018	117.0	365.4	6.8	(9.2)	–	480.0

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-based rates. Our consolidated revenues reflect the elimination of intercompany transactions. Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base.

We include equity in income of unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Equity investments with industry partners are a significant component of our business strategy. They are a means by which we conduct our operations to align our interests with those of customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed. Many of these businesses perform supporting or complementary roles to our other midstream business operations.

Our integrated midstream energy asset network (including the midstream energy assets owned by our unconsolidated affiliates) provides services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. In general, hydrocarbons may enter our asset system in a number of ways, such as through a natural gas gathering pipeline, natural gas processing facility, a crude oil pipeline or terminal, an NGL fractionator, an NGL storage facility or an NGL gathering or transportation pipeline. The assets of many of our equity investees are included within our integrated midstream network. For example, we use the Front Range Pipeline and Texas Express Pipeline to transport mixed NGLs to our Mont Belvieu NGL fractionation and storage complex and the Seaway Pipeline to transport crude oil to our terminals in the Houston, Texas area. Given the integral nature of these equity method investees to our operations, we believe the presentation of equity earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Information by business segment, together with reconciliations to our Consolidated Balance Sheet totals, is presented in the following table:

	Reportable Business Segments					
	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Adjustments and Eliminations	Consolidated Total
Property, plant and equipment, net: (see Note 4)						
At December 31, 2020	$ 17,128.3	$ 6,982.6	$ 8,465.8	$ 7,528.4	$ 1,807.7	$ 41,912.8
At December 31, 2019	16,652.1	6,324.4	8,432.5	7,553.2	2,641.2	41,603.4
At December 31, 2018	14,845.4	5,847.7	8,303.8	6,213.9	3,526.8	38,737.6
Investments in unconsolidated affiliates: (see Note 5)						
At December 31, 2020	671.6	1,723.7	31.4	2.5	–	2,429.2
At December 31, 2019	703.8	1,866.5	27.3	2.6	–	2,600.2
At December 31, 2018	662.0	1,867.5	22.8	62.8	–	2,615.1
Intangible assets, net: (see Note 6)						
At December 31, 2020	334.1	1,936.6	905.0	133.4	–	3,309.1
At December 31, 2019	360.2	2,001.9	941.2	145.7	–	3,449.0
At December 31, 2018	380.1	2,094.6	979.3	154.4	–	3,608.4
Goodwill: (see Note 6)						
At December 31, 2020	2,651.7	1,841.0	–	956.2	–	5,448.9
At December 31, 2019	2,651.7	1,841.0	296.3	956.2	–	5,745.2
At December 31, 2018	2,651.7	1,841.0	296.3	956.2	–	5,745.2
Segment assets:						
At December 31, 2020	20,785.7	12,483.9	9,402.2	8,620.5	1,807.7	53,100.0
At December 31, 2019	20,367.8	12,033.8	9,697.3	8,657.7	2,641.2	53,397.8
At December 31, 2018	18,539.2	11,650.8	9,602.2	7,387.3	3,526.8	50,706.3

Segment assets consist of property, plant and equipment, investments in unconsolidated affiliates, intangible assets and goodwill. The carrying values of such amounts are assigned to each segment based on each asset's or investment's principal operations and contribution to the gross operating margin of that particular segment. Since construction-in-progress (a component of property, plant and equipment) does not contribute to segment gross operating margin, such amounts are excluded from segment asset totals until the underlying assets are placed in service. Intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate. The remainder of our consolidated total assets, which consist primarily of working capital assets, are excluded from segment assets since these amounts are not attributable to one specific segment (e.g. cash).

Supplemental Revenue and Expense Information

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

	For the Year Ended December 31, 2020	2019	2018
Consolidated revenues:			
NGL Pipelines & Services	$ 11,177.2	$ 13,470.7	$ 15,648.9
Crude Oil Pipelines & Services	6,689.0	10,287.3	11,042.6
Natural Gas Pipelines & Services	2,553.1	3,169.4	3,454.4
Petrochemical & Refined Products Services	6,780.4	5,861.8	6,388.3
Total consolidated revenues	$ 27,199.7	$ 32,789.2	$ 36,534.2
Consolidated costs and expenses:			
Operating costs and expenses:			
Cost of sales	$ 16,723.2	$ 22,065.8	$ 26,789.8
Other operating costs and expenses (1)	2,800.2	3,020.7	2,898.7
Depreciation, amortization and accretion	1,961.5	1,848.3	1,687.0
Impairment of goodwill	296.3	–	–
Impairment of assets other than goodwill	594.3	132.7	50.5
Net gains attributable to asset sales	(4.4)	(5.7)	(28.7)
General and administrative costs	219.6	211.7	208.3
Total consolidated costs and expenses	$ 22,590.7	$ 27,273.5	$ 31,605.6

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

Fluctuations in our product sales revenues and related cost of sales amounts are explained in part by changes in energy commodity prices. In general, lower energy commodity prices result in a decrease in our revenues attributable to product sales; however, these lower commodity prices also decrease the associated cost of sales as purchase costs are lower. The same type of correlation would be true in the case of higher energy commodity sales prices and purchase costs.

Major Customer Information

Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base. No single customer accounted for 10% or more of our consolidated revenues (thus constituting a "major customer") during the years ended December 31, 2020 or 2018. However, Vitol Holding B.V. and its affiliates (collectively, "Vitol") accounted for $3.31 billion, or 10.1%, of our consolidated revenues during the year ended December 31, 2019. Vitol is a global energy and commodity trading company. The following table presents our consolidated revenues from Vitol by business segment for the year ended December 31, 2019:

NGL Pipelines & Services	$ 1,410.8
Crude Oil Pipelines & Services	1,670.7
Natural Gas Pipelines & Services	31.2
Petrochemical & Refined Products Services	202.1
Total	$ 3,314.8

Note 11. Earnings Per Unit

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

	For the Year Ended December 31, 2020	2019	2018
BASIC EARNINGS PER COMMON UNIT			
Net income attributable to common unitholders	$ 3,774.7	$ 4,591.3	$ 4,172.4
Earnings allocated to phantom unit awards (1)	(32.0)	(27.7)	(21.5)
Net income allocated to common unitholders	$ 3,742.7	$ 4,563.6	$ 4,150.9
Basic weighted-average number of common units outstanding	2,185.8	2,188.6	2,176.5
Basic earnings per common unit	$ 1.71	$ 2.09	$ 1.91
DILUTED EARNINGS PER COMMON UNIT			
Net income attributable to common unitholders	$ 3,774.7	$ 4,591.3	$ 4,172.4
Net income attributable to preferred units	0.9	–	–
Net income attributable to limited partners	$ 3,775.6	$ 4,591.3	$ 4,172.4
Diluted weighted-average number of units outstanding:			
Distribution-bearing common units	2,185.8	2,188.6	2,176.5
Phantom units (2)	15.7	13.1	10.5
Preferred units (2)	0.7	–	–
Total	2,202.2	2,201.7	2,187.0
Diluted earnings per common unit	$ 1.71	$ 2.09	$ 1.91

(1) Phantom units are considered participating securities for purposes of computing basic earnings per unit. See Note 13 for information regarding our phantom units.

(2) We use the "if-converted method" to determine the potential dilutive effect of the vesting of phantom units and the conversion of preferred units outstanding. See Note 8 for information regarding the preferred units issued during 2020.

Note 12. Business Combinations

Acquisition of Delaware Processing

In March 2018, we acquired the remaining 50% member interest in our former Delaware Processing joint venture for $151 million in cash, net of $3.9 million of cash held by the venture. As a result, Delaware Processing became a wholly-owned consolidated subsidiary of ours. Delaware Processing owns a cryogenic natural gas processing facility having a capacity of 150 million cubic feet per day ("MMcf/d"). The facility, which is located in Reeves County, Texas and entered service in August 2016, serves producers in the Delaware Basin in West Texas and southern New Mexico.

The following table presents the final fair value allocation of assets acquired and liabilities assumed in the Delaware Processing acquisition.

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

Prior to this acquisition, we accounted for our investment using the equity method. On a historical pro forma basis, our consolidated revenues, costs and expenses, operating income, net income attributable to Enterprise Products Partners L.P. and earnings per unit amounts for the year ended December 31, 2018 would not have differed materially from those we reported had the acquisition been completed on January 1, 2018 rather than March 29, 2018.

At March 29, 2018, our 50% equity investment in Delaware Processing was recorded at $107.0 million. Upon acquisition of the remaining 50% member interest, our existing equity investment was remeasured to fair value resulting in the recognition of a non-cash $39.4 million gain, which is presented within "Other income (expense)" on our Consolidated Statement of Operations for the year ended December 31, 2018.

The results for this business are reported under the NGL Pipelines & Services business segment.

Note 13. Equity-Based Awards

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

	For the Year Ended December 31,					
	2020		2019		2018	
Equity-classified awards:						
Phantom unit awards	$	150.3	$	132.2	$	99.7
Profits interest awards		8.7		11.6		6.1
Liability-classified awards		0.1		0.1		0.3
Total	$	159.1	$	143.9	$	106.1

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

Phantom Unit Awards

Subject to customary forfeiture provisions, phantom unit awards allow recipients to acquire EPD common units once a defined vesting period expires (at no cost to the recipient apart from fulfilling required service and other conditions). We expect phantom units to result in the issuance of common units upon vesting; therefore, these grants are accounted for as equity-classified awards. Phantom unit awards generally vest at a rate of 25% per year beginning one year after the grant date and are non-vested until the required service periods expire.

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

The following table presents phantom unit award activity for the years indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Phantom unit awards at December 31, 2017	9,289,501	$ 27.65
Granted (2)	5,006,181	$ 26.82
Vested	(3,479,958)	$ 28.57
Forfeited	(482,447)	$ 26.88
Phantom unit awards at December 31, 2018	10,333,277	$ 26.97
Granted (3)	6,854,920	$ 27.75
Vested	(3,895,049)	$ 27.53
Forfeited	(318,464)	$ 27.21
Phantom unit awards at December 31, 2019	12,974,684	$ 27.21
Granted (4)	7,405,245	$ 25.71
Vested	(4,532,269)	$ 26.35
Forfeited	(178,218)	$ 26.73
Phantom unit awards at December 31, 2020	15,669,442	$ 26.76

(1) Determined by dividing the aggregate grant date fair value of awards (before an allowance for forfeitures) by the number of awards issued.
(2) The aggregate grant date fair value of phantom unit awards issued during 2018 was $134.3 million based on a grant date market price of EPD common units ranging from $25.40 to $29.22 per unit. An estimated annual forfeiture rate of 3.2% was applied to these awards.
(3) The aggregate grant date fair value of phantom unit awards issued during 2019 was $190.2 million based on a grant date market price of EPD common units ranging from $26.32 to $29.29 per unit. An estimated annual forfeiture rate of 3.0% was applied to these awards.
(4) The aggregate grant date fair value of phantom unit awards issued during 2020 was $190.4 million based on a grant date market price of EPD common units ranging from $16.95 to $25.76 per unit. An estimated annual forfeiture rate of 2.4% was applied to these awards.

The phantom unit awards were granted under the 2008 Plan, which is a long-term incentive plan under which any employee or consultant of EPCO, us or our affiliates that provides services to us, directly or indirectly, may receive incentive compensation awards in the form of phantom units, options, restricted common units, unit appreciation rights, unit awards, other unit-based awards or substitute awards. Non-employee directors of our general partner may also participate in the 2008 Plan.

The maximum number of EPD common units authorized for issuance under the 2008 Plan was 55,000,000 at December 31, 2020. This amount automatically increased under the terms of the 2008 Plan by 5,000,000 common units on January 1, 2021 and will continue to automatically increase annually on January 1 thereafter during the term of the 2008 Plan; provided, however, that in no event shall the maximum aggregate number exceed 70,000,000 common units. The 2008 Plan is effective until September 30, 2023 or, if earlier, until (i) the time that all available common units under the 2008 Plan have been delivered to participants or (ii) the time of termination of the 2008 Plan by the Board of Directors of EPCO or by the Incentive Plan Administration Subcommittee of the Governance Committee of Enterprise GP. After giving effect to awards granted under the 2008 Plan through December 31, 2020, a total of 16,229,995 additional common units were available for issuance. After taking into account tax withholding requirements, we issued 3,162,095, 2,720,603 and 2,442,436 common units in connection with the vesting of phantom unit awards in the years ended December 31, 2020, 2019 and 2018, respectively.

The 2008 Plan provides for the issuance of DERs in connection with phantom unit awards. A DER entitles the participant to nonforfeitable cash payments equal to the product of the number of phantom unit awards outstanding for the participant and the cash distribution per common unit paid by EPD to its common unitholders. Cash payments made in connection with DERs are charged to partners' equity when the phantom unit award is expected to result in the issuance of common units; otherwise, such amounts are expensed.

The following table presents supplemental information regarding phantom unit awards for the years indicated:

	For the Year Ended December 31,		
	2020	2019	2018
Cash payments made in connection with DERs	$ 27.1	$ 22.1	$ 17.7
Total intrinsic value of phantom unit awards that vested during period	$ 114.8	$ 111.1	$ 90.7

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was $156.7 million at December 31, 2020, of which our share of such cost is currently estimated to be $129.6 million. Due to the graded vesting provisions of these awards, we expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.0 years.

Profits Interest Awards

In 2016 and 2018, EPCO Holdings Inc. ("EPCO Holdings"), a privately held affiliate of EPCO, contributed a portion of the EPD common units it owned to form limited partnerships (referred to as "Employee Partnerships") that serve as long-term incentive arrangements for key employees of EPCO by providing them a "profits interest" in an Employee Partnership. The Employee Partnerships named (i) EPD PubCo Unit I L.P. ("PubCo I"), (ii) EPD PubCo Unit II L.P. ("PubCo II"), and (iii) EPD PrivCo Unit I L.P. ("PrivCo I") were formed by EPCO Holdings in 2016. The Employee Partnerships named (i) EPD 2018 Unit IV L.P. ("EPD IV") and (ii) EPCO Unit II L.P. ("EPCO II") were formed by EPCO Holdings in 2018. The Class B limited partner interests of PubCo I vested in February 2020.

In September 2020, the partners of PubCo II and PrivCo I amended their respective limited partnership agreements to provide for the vesting of their Class B limited partner interests on the earlier of (i) February 22, 2023, (ii) the first date on or after September 30, 2020 on which the closing market price of the Partnership's common units is equal to or greater than $25.41 per unit, (iii) a change of control event, or (iv) dissolution of the applicable Employee Partnership. As a result of these modifications, PubCo II and PrivCo I will recognize incremental compensation cost of $1.2 million and $0.5 million, respectively, through February 22, 2023.

In exchange for the contributions of EPD common units, EPCO Holdings was admitted as the Class A limited partner of each Employee Partnership. Also on the applicable contribution date, certain key EPCO employees were issued Class B limited partner interests (i.e., profits interest awards) and admitted as Class B limited partners of each Employee Partnership, all without any capital contribution by such employees. EPCO serves as the general partner of each Employee Partnership.

Each quarter, the Employee Partnerships, as owners of EPD common units, receive a cash distribution from EPD as do EPD's other common unitholders. The cash received by the Employee Partnership is first used to pay the Class A limited partner a cash distribution equal to the product of (i) the number of EPD common units owned by the Employee Partnership and (ii) the Class A Preference Return (subject to equitable adjustment in order to reflect any equity split, equity distribution or dividend, reverse split, combination, reclassification, recapitalization or other similar event affecting such common units). To the extent that the Employee Partnership has cash remaining after making this quarterly payment to the Class A limited partner, the residual cash is distributed to the Class B limited partners on a quarterly basis as a distribution.

Upon liquidation of an Employee Partnership, assets having a then current fair market value equal to the Class A limited partner's capital base in such Employee Partnership will be distributed to the Class A limited partner. Any remaining assets of such Employee Partnership will be distributed to the Class B limited partners of such Employee Partnership as a residual profits interest, which represents the appreciation in value of the Employee Partnership's assets since the date of EPCO Holdings' contribution to it, as described above.

Unless otherwise agreed to by EPCO and a majority in interest of the limited partners of each Employee Partnership, such Employee Partnership will terminate at the earliest to occur of (i) 30 days following its vesting date, (ii) a change of control or (iii) a dissolution of the Employee Partnership.

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

The following table summarizes key elements of each Employee Partnership as of December 31, 2020:

Employee Partnership	Partnership Common Units Contributed by EPCO Holdings	Class A Capital Base (1)	Class A Preference Return	Expected Vesting/ Liquidation Date	Estimated Fair Value of Profits Interest Awards (2)	Unrecognized Compensation Cost (3)
PubCo II	2,834,198	$66.3 million	$0.3900	February 2023	$2.5 million	$2.3 million
PrivCo I	1,111,438	$26.0 million	$0.3900	February 2023	$0.9 million	$0.2 million
EPD IV	6,400,000	$172.9 million	$0.4325	December 2023	$26.7 million	$13.6 million
EPCO II	1,600,000	$43.2 million	$0.4325	December 2023	$6.6 million	$0.3 million

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

(2) Represents the total fair value of the profits interest awards awarded to the Class B limited partners of each Employee Partnership irrespective of how such costs will be allocated between us and EPCO and its privately held affiliates. The fair value is as of the grant date or as of the plan modification date, as applicable.

(3) Represents our expected share of the unrecognized compensation cost at December 31, 2020. We expect to recognize our share of the unrecognized compensation cost for PubCo II, PrivCo I, EPD IV and EPCO II over a weighted-average period of 2.1 years, 2.1 years, 2.9 years and 2.9 years, respectively.

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

The following table summarizes the assumptions we used in applying a Black-Scholes option pricing model or Monte Carlo model, as applicable, to derive that portion of the estimated fair value of the profits interest awards (at either the grant date or modification date) for each Employee Partnership:

Employee Partnership	Expected Life of Award from Grant Date	Risk-Free Interest Rate	Expected Distribution Yield	Expected Unit Price Volatility
PubCo II	7.0 years	0.1% to 3.0%	5.9% to 7.0%	19% to 40%
PrivCo I	7.0 years	0.1% to 1.6%	6.1% to 6.7%	19% to 40%
EPD IV	5.0 years	2.8%	6.5%	27%
EPCO II	5.0 years	1.6% to 2.8%	6.3% to 6.8%	24% to 27%

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

Note 14. Hedging Activities and Fair Value Measurements

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with assets, liabilities and certain anticipated future transactions, we use derivative instruments such as futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward-starting swaps, options to enter into forward-starting swaps ("swaptions"), and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy may be used in controlling our overall cost of capital associated with such borrowings.

Swaptions

In 2019 and 2018, we sold options to be put into forward-starting swaps, or swaptions, if the market rate of interest fell below the strike rate of the option upon expiration of the derivative instrument. The premiums we realized upon sale of the swaptions are reflected as a $23.1 million and $29.4 million reduction in interest expense for the year ended December 31, 2019 and 2018, respectively.

Due to declining interest rates, the counterparties to swaptions we sold in July 2019 exercised their right to put us into ten forward-starting swaps in September 2019 having an aggregate notional value of $1.0 billion. Since the swaptions were not designated as hedging instruments and were subject to mark-to-market accounting, we incurred an unrealized, mark-to-market loss at inception of the forward-starting swaps totaling $94.9 million that is reflected as an increase in interest expense for the year ended December 31, 2019. The ten forward-starting swaps resulting from the swaption exercise in September 2019 were designated as hedging instruments and are subject to cash flow hedge accounting.

Forward-Starting Swaps

Forward-starting swaps hedge the risk of an increase in underlying benchmark interest rates during the period of time between the inception date of the swap agreement and the future date of a debt issuance. Under the terms of the forward-starting swaps, we pay to the counterparties (at the expected settlement dates of the instruments) amounts based on a fixed interest rate applied to a notional amount and receive from the counterparties an amount equal to a variable interest rate (based on LIBOR or an equivalent index rate) on the same notional amount.

The following table summarizes our portfolio of 30-year forward-starting swaps at December 31, 2020, all of which are associated with the expected future issuance of senior notes.

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Expected Settlement Date	Weighted-Average Fixed Rate Locked	Accounting Treatment
Future long-term debt offering	1 forward-starting swap	$75.0	4/2021	2.41%	Cash flow hedge
Future long-term debt offering	5 forward-starting swaps	$500.0	4/2021	2.13%	Cash flow hedge
Future long-term debt offering	2 forward-starting swaps (1)	$150.0	2/2022	1.72%	Cash flow hedge
Future long-term debt offering	1 forward starting swap (1)	$100.0	4/2021	1.46%	Cash flow hedge
Future long-term debt offering	2 forward starting swaps (1)	$150.0	2/2022	1.48%	Cash flow hedge
Future long-term debt offering	2 forward starting swaps (1)	$100.0	2/2022	0.95%	Cash flow hedge

(1) These swaps were entered into during the first quarter of 2020.

In total, the notional amount of forward-starting swaps outstanding at December 31, 2020 was $1.08 billion. The weighted-average fixed interest rate of these derivative instruments is 1.83%.

As a result of market conditions, we terminated an aggregate $575 million notional amount of forward-starting swaps in 2020, which resulted in net cash payments of $33.3 million. As cash flow hedges, losses on these derivative instruments are reflected as a component of accumulated other comprehensive loss and are being amortized to earnings (as an increase in interest expense) over the 30-year life of the associated debt through January 2051. These swaps were unwound in connection with our issuance of Senior Notes BBB. During 2018, we terminated an aggregate $275 million notional amount of forward-starting swaps, which resulted in cash proceeds totaling $22.1 million. As cash flow hedges, gains on these derivative instruments are reflected as a component of accumulated other comprehensive income and are being amortized to earnings (as a decrease in interest expense) over the 30-year life of the associated debt through February 2049.

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, petrochemicals and refined products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps and basis swaps.

At December 31, 2020, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging natural gas processing margins and (iii) hedging the fair value of commodity products held in inventory.

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

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

- The objective of our inventory hedging program is to hedge the fair value of commodity products currently held in inventory by locking in the sales price of the inventory through the use of derivative instruments and related contracts.

The following table summarizes our portfolio of commodity derivative instruments outstanding at December 31, 2020 (volume measures as noted):

Derivative Purpose	Volume (1) Current (2)	Volume (1) Long-Term (2)	Accounting Treatment
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	6.0	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls)	0.6	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities (Bcf)	4.0	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	142.8	1.6	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	172.1	4.5	Cash flow hedge
NGLs inventory management activities (MMBbls)	1.9	n/a	Fair value hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	41.2	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	51.1	3.3	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.8	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	32.9	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	44.5	n/a	Cash flow hedge
Petrochemical marketing:			
Forecasted purchases of petrochemical products (MMBbls)	0.4	n/a	Cash flow hedge
Forecasted sales of petrochemical products (MMBbls)	0.5	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3)	10.3	0.4	Mark-to-market
NGL risk management activities (MMBbls) (3)	26.5	7.9	Mark-to-market
Refined products risk management activities (MMBbls) (3)	6.9	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (3)	32.5	2.6	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is December 2022, December 2021 and October 2023, respectively.
(3) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

The carrying amount of our inventories subject to fair value hedges was $144.0 million and $31.7 million at December 31, 2020 and 2019, respectively.

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of commodity products. There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur during the periods originally forecasted. In accordance with derivatives accounting guidance, these instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of the underlying assets. Due to volatility in commodity prices, any non-cash, mark-to-market earnings variability cannot be predicted.

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

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

	Asset Derivatives				Liability Derivatives			
	December 31, 2020		December 31, 2019		December 31, 2020		December 31, 2019	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments								
Interest rate derivatives	Current assets	$ –	Current assets	$ –	Current liabilities	$ 109.1	Current liabilities	$ 6.7
Interest rate derivatives	Other assets	12.4	Other assets	–	Other liabilities	11.0	Other liabilities	6.8
Total interest rate derivatives		12.4		–		120.1		13.5
Commodity derivatives	Current assets	210.5	Current assets	116.5	Current liabilities	234.0	Current liabilities	107.1
Commodity derivatives	Other assets	0.4	Other assets	–	Other liabilities	6.1	Other liabilities	–
Total commodity derivatives		210.9		116.5		240.1		107.1
Total derivatives designated as hedging instruments		$ 223.3		$ 116.5		$ 360.2		$ 120.6
Derivatives not designated as hedging instruments								
Commodity derivatives	Current assets	18.1	Current assets	10.7	Current liabilities	6.1	Current liabilities	8.6
Commodity derivatives	Other assets	0.2	Other assets	0.6	Other liabilities	0.1	Other liabilities	0.5
Total commodity derivatives		18.3		11.3		6.2		9.1
Total derivatives not designated as hedging instruments		$ 18.3		$ 11.3		$ 6.2		$ 9.1

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

	Offsetting of Financial Assets and Derivative Assets						
				Gross Amounts Not Offset in the Balance Sheet			
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Financial Instruments	Cash Collateral Paid	Cash Collateral Received	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)		(iv)		(v) = (iii) + (iv)
As of December 31, 2020:							
Interest rate derivatives	$ 12.4	$ –	$ 12.4	$ –	$ –	$ –	$ 12.4
Commodity derivatives	229.2	–	229.2	(228.5)	–	–	0.7
As of December 31, 2019:							
Commodity derivatives	$ 127.8	–	$ 127.8	$ (115.3)	$ (11.0)	$ –	$ 1.5

	Offsetting of Financial Liabilities and Derivative Liabilities					
				Gross Amounts Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Financial Instruments	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)		(v) = (iii) + (iv)
As of December 31, 2020:						
Interest rate derivatives	$ 120.1	$ –	$ 120.1	$ –	$ –	$ 120.1
Commodity derivatives	246.3	–	246.3	(228.5)	(17.3)	0.5
As of December 31, 2019:						
Interest rate derivatives	$ 13.5	$ –	$ 13.5	$ –	$ –	$ 13.5
Commodity derivatives	116.2	–	116.2	(115.3)	–	0.9

Derivative assets and liabilities recorded on our Consolidated Balance Sheets are presented on a gross-basis and determined at the individual transaction level. This presentation method is applied regardless of whether the respective exchange clearing agreements, counterparty contracts or master netting agreements contain netting language often referred to as "rights of offset." Although derivative amounts are presented on a gross-basis, having rights of offset enable the settlement of a net as opposed to gross receivable or payable amount under a counterparty default or liquidation scenario.

Cash is paid and received as collateral under certain agreements, particularly for those associated with exchange transactions. For any cash collateral payments or receipts, corresponding assets or liabilities are recorded to reflect the variation margin deposits or receipts with exchange clearing brokers and customers. These balances are also presented on a gross-basis on our Consolidated Balance Sheets.

The tabular presentation above provides a means for comparing the gross amount of derivative assets and liabilities, excluding associated accounts payable and receivable, to the net amount that would likely be receivable or payable under a default scenario based on the existence of rights of offset in the respective derivative agreements. Any cash collateral paid or received is reflected in these tables, but only to the extent that it represents variation margins. Any amounts associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from these tables.

The following tables present the effect of our derivative instruments designated as fair value hedges on our Statements of Consolidated Operations for the years indicated:

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative		
		For the Year Ended December 31,		
		2020	2019	2018
Interest rate derivatives	Interest expense	$ –	$ –	$ 1.3
Commodity derivatives	Revenue	(88.0)	2.2	9.9
Total		$ (88.0)	$ 2.2	$ 11.2

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item		
		For the Year Ended December 31,		
		2020	2019	2018
Interest rate derivatives	Interest expense	$ –	$ –	$ (1.4)
Commodity derivatives	Revenue	168.1	6.9	(6.9)
Total		$ 168.1	$ 6.9	$ (8.3)

The gain (loss) corresponding to the hedge ineffectiveness on the fair value hedges was negligible for all periods presented. The remaining gain (loss) for each period presented is primarily attributable to prompt-to-forward month price differentials that were excluded from the assessment of hedge effectiveness.

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

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income (Loss) On Derivative		
	For the Year Ended December 31,		
	2020	2019	2018
Interest rate derivatives	$ (127.5)	$ 81.4	$ 22.2
Commodity derivatives – Revenue (1)	134.7	55.8	293.0
Commodity derivatives – Operating costs and expenses (1)	(10.3)	(11.7)	0.2
Total	$ (3.1)	$ 125.5	$ 315.4

(1) The fair value of these derivative instruments will be reclassified to their respective locations on the Statement of Consolidated Operations when the forecasted transactions affect earnings.

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) to Income		
		For the Year Ended December 31,		
		2020	2019	2018
Interest rate derivatives	Interest expense	$ (39.3)	$ (37.3)	$ (38.1)
Commodity derivatives	Revenue	282.6	152.4	131.7
Commodity derivatives	Operating costs and expenses	(9.9)	(10.7)	(1.3)
Total		$ 233.4	$ 104.4	$ 92.3

Over the next twelve months, we expect to reclassify $41.2 million of losses attributable to interest rate derivative instruments from accumulated other comprehensive loss to earnings as an increase in interest expense. Likewise, we expect to reclassify $35.6 million of losses attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings, with $36.0 million as a decrease in revenue and $0.4 million as a decrease in operating costs and expenses.

The following table presents the effect of our derivative instruments not designated as hedging instruments on our Statements of Consolidated Operations for the years indicated:

Derivatives Not Designated as Hedging Instruments	Location	Gain (Loss) Recognized in Income on Derivative		
		For the Year Ended December 31,		
		2020	2019	2018
Interest rate derivatives	Interest expense	$ –	$ (94.9)	$ –
Commodity derivatives	Revenue	166.0	102.2	(462.9)
Commodity derivatives	Operating costs and expenses	(0.2)	(12.4)	8.2
Total		$ 165.8	$ (5.1)	$ (454.7)

The $165.8 million gain recognized for the year ended December 31, 2020 (as noted in the preceding table) from derivatives not designated as hedging instruments consists of $92.1 million of realized gains and $73.7 million of net unrealized mark-to-market gains attributable to commodity derivatives.

In total and inclusive of both fair value hedges and derivatives not designated as hedging instruments, unrealized mark-to-market gains (losses) included in gross operating margin and interest expense for the years indicated:

	For the Year Ended December 31,		
	2020	2019	2018
Mark-to-market gains (losses) in gross operating margin:			
NGL Pipelines & Services	$ 48.4	$ (5.5)	$ 18.0
Crude Oil Pipelines & Services	20.1	80.6	(44.1)
Natural Gas Pipelines & Services	6.3	(0.2)	6.7
Petrochemical & Refined Products Services	4.5	(7.2)	1.7
Total mark-to-market impact on gross operating margin	79.3	67.7	(17.7)
Mark-to-market gains (losses) in interest expense	–	(94.9)	(0.1)
Total	$ 79.3	$ (27.2)	$ (17.8)

Fair Value Measurements

The following tables set forth, by level within the Level 1, 2 and 3 fair value hierarchy (see Note 2), the carrying values of our financial assets and liabilities at the dates indicated. These assets and liabilities are measured on a recurring basis and are classified based on the lowest level of input used to estimate their fair value. Our assessment of the relative significance of such inputs requires judgment.

The values for commodity derivatives are presented before and after the application of Chicago Mercantile Exchange ("CME") Rule 814, which deems that financial instruments cleared by the CME are settled daily in connection with variation margin payments. As a result of this exchange rule, CME-related derivatives are considered to have no fair value at the balance sheet date for financial reporting purposes; however, the derivatives remain outstanding and subject to future commodity price fluctuations until they are settled in accordance with their contractual terms. Derivative transactions cleared on exchanges other than the CME (e.g., the Intercontinental Exchange or ICE) continue to be reported on a gross basis.

	At December 31, 2020 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets:				
Interest rate derivatives	$ –	$ 12.4	$ –	$ 12.4
Commodity derivatives:				
Value before application of CME Rule 814	678.6	878.6	12.9	1,570.1
Impact of CME Rule 814 change	(678.6)	(650.4)	(11.9)	(1,340.9)
Total commodity derivatives	–	228.2	1.0	229.2
Total	$ –	$ 240.6	$ 1.0	$ 241.6
Financial liabilities:				
Interest rate derivatives	$ –	$ 120.1	$ –	$ 120.1
Commodity derivatives:				
Value before application of CME Rule 814	1,065.6	1,047.4	25.9	2,138.9
Impact of CME Rule 814 change	(1,065.6)	(807.3)	(19.7)	(1,892.6)
Total commodity derivatives	–	240.1	6.2	246.3
Total	$ –	$ 360.2	$ 6.2	$ 366.4

In the aggregate, the fair value of our commodity hedging portfolios at December 31, 2020 was a net derivative liability of $568.8 million prior to the impact of CME Rule 814.

	At December 31, 2019 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets:				
Commodity derivatives:				
Value before application of CME Rule 814	$ 53.4	$ 343.7	$ 0.1	$ 397.2
Impact of CME Rule 814 change	(47.0)	(222.4)	–	(269.4)
Total commodity derivatives	6.4	121.3	0.1	127.8
Total	$ 6.4	$ 121.3	$ 0.1	$ 127.8
Financial liabilities:				
Liquidity Option (see Note 17)	$ –	$ –	$ 509.6	$ 509.6
Interest rate derivatives	–	13.5	–	13.5
Commodity derivatives:				
Value before application of CME Rule 814	88.1	273.6	0.3	362.0
Impact of CME Rule 814 change	(81.9)	(163.9)	–	(245.8)
Total commodity derivatives	6.2	109.7	0.3	116.2
Total	$ 6.2	$ 123.2	$ 509.9	$ 639.3

Prior to being settled on March 5, 2020, the recurring fair value measurement pertaining to the Liquidity Option was based on a number of Level 3 inputs. For information regarding the Liquidity Option prior to its settlement, see Note 17.

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

	Location	For the Year Ended December 31, 2020	2019
Financial liability balance, net, January 1		$ (509.8)	$ (395.9)
Total gains (losses) included in:			
Net income (1)	Revenue	(1.6)	3.7
Net income	Other expense, net – Liquidity Option	(2.3)	(119.6)
Other comprehensive income (loss)	Commodity derivative instruments – changes in fair value of cash flow hedges	(23.7)	(2.1)
Settlements (1)	Revenue	3.2	(3.5)
Transfer out of Level 3 – Liquidity Option (2)		511.9	–
Other transfers out of Level 3		17.1	7.6
Financial liability balance, net, December 31		$ (5.2)	$ (509.8)

(1) There were $0.7 million and $0.2 million of unrealized gains included in these amounts for the years ended December 31, 2020 and 2019, respectively.

(2) In March 2020, the Liquidity Option settled and was transferred out of Level 3. See Note 17 for information regarding the Liquidity Option.

Nonrecurring Fair Value Measurements

We wrote down the assets comprising our marine transportation business and certain natural gas gathering and processing activities to their estimated fair values in 2020 (see Note 4). Apart from these matters, we did not have any significant nonrecurring fair value measurements during the years ended December 31, 2020, 2019 or 2018. The following table presents information regarding our significant nonrecurring fair value measurements at December 31, 2020:

	Components of Carrying Value at December 31, 2020 by Level of Fair Value Measurement				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Other Observable Inputs** (Level 2)	**Significant Unobservable Inputs** (Level 3)	**Carrying Values at December 31, 2020**	**Impairment Charges Recognized in 2020**
Long-lived assets held and used: (1)					
Marine transportation business	$ –	$ –	$ 410.0	$ 410.0	$ 256.7
South Texas natural gas gathering and processing	–	–	21.3	21.3	125.7

(1) Our fair value estimates for these assets were based on an income approach (i.e., a discounted cash flow approach).

Our fair value estimate of $410.0 million for the marine transportation business is based on the income approach to fair value, which relies on the use of a discounted cash flow model. Our valuation estimate for this business at December 31, 2020 incorporates several Level 3 inputs such as: (i) management's long-term forecast of cash flows generated by the business; (ii) a discount rate of 9.3%; and (iii) a growth rate of 2.1% for terminal year cash flows. The discount rate used in this analysis is based on an estimated weighted-average cost of capital for market participants engaged in marine transportation activities.

Our fair value estimate for the South Texas natural gas gathering and processing assets of $21.3 million is based primarily on management expectations of the residual values of such facilities and pipelines based on historical experience.

Other Fair Value Information

The carrying amounts of cash and cash equivalents (including restricted cash balances), accounts receivable, commercial paper notes and accounts payable approximate their fair values based on their short-term nature. The estimated total fair value of our fixed-rate debt obligations was $35.00 billion and $30.37 billion at December 31, 2020 and 2019, respectively. The aggregate carrying value of these debt obligations was $29.90 billion and $27.15 billion at December 31, 2020 and 2019, respectively. These values are primarily based on quoted market prices for such debt or debt of similar terms and maturities (Level 2) and our credit standing. Changes in market rates of interest affect the fair value of our fixed-rate debt. The carrying values of our variable-rate long-term debt obligations approximate their fair values since the associated interest rates are market-based. We do not have any long-term investments in debt or equity securities recorded at fair value.

Note 15. Related Party Transactions

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

	For the Year Ended December 31,		
	2020	2019	2018
Revenues – related parties:			
Unconsolidated affiliates	$ 36.7	$ 67.3	$ 107.7
Costs and expenses – related parties:			
EPCO and its privately held affiliates	$ 1,143.7	$ 1,145.3	$ 1,089.6
Unconsolidated affiliates	203.1	403.1	447.4
Total	$ 1,346.8	$ 1,548.4	$ 1,537.0

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

	December 31,	
	2020	2019
Accounts receivable - related parties:		
EPCO and its privately held affiliates	$ 1.9	$ –
Unconsolidated affiliates	3.7	2.5
Total	$ 5.6	$ 2.5
Accounts payable - related parties:		
EPCO and its privately held affiliates	$ 139.6	$ 143.7
Unconsolidated affiliates	9.9	18.6
Total	$ 149.5	$ 162.3

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

Relationship with EPCO and Affiliates

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

At December 31, 2020, EPCO and its privately held affiliates (including Dan Duncan LLC and certain Duncan family trusts) beneficially owned the following limited partner interests in us:

Total Number of Limited Partner Interests Held	Percentage of Limited Partner Interests Outstanding
701,993,298 common units	32.2%
15,138 preferred units	30.2%

Of the total number of units held by EPCO and its privately held affiliates, 92,976,464 have been pledged as security under the credit facilities of EPCO and its privately held affiliates at December 31, 2020. These credit facilities contain customary and other events of default, including defaults by us and other affiliates of EPCO. An event of default, followed by a foreclosure on the pledged collateral, could ultimately result in a change in ownership of these units and affect the market price of EPD's common units.

The Partnership and Enterprise GP are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are also separate from those of EPCO and its other affiliates. EPCO and its privately held affiliates depend on the cash distributions they receive from us and other investments to fund their other activities and to meet their debt obligations. During the years ended December 31, 2020, 2019 and 2018, we paid EPCO and its privately held affiliates cash distributions totaling $1.21 billion, $1.19 billion and $1.16 billion, respectively.

From time-to-time, EPCO and its privately held affiliates elect to purchase additional common units under EPD's DRIP and ATM program. During the years ended December 31, 2019 and 2018, privately held affiliates of EPCO reinvested $29 million and $213 million, respectively, through our DRIP. See Note 8 for additional information regarding our DRIP and ATM program.

We lease office space from privately held affiliates of EPCO at rental rates that approximate market rates. In January 2020, we amended an office space lease with an affiliate of EPCO that extended the term through June 2037. For the years ended December 31, 2020, 2019 and 2018, we recognized $13.0 million, $14.9 million and $13.9 million, respectively, of related party operating lease expense in connection with these office space leases.

EPCO ASA. We have no employees. All of our administrative and operating functions are provided either by employees of EPCO (pursuant to the ASA) or by other service providers. We and our general partner are parties to the ASA.

Under the ASA, EPCO provides us with the administrative and operating services deemed necessary to manage and operate our businesses, properties and assets (all in accordance with prudent industry practices). Our operating costs and expenses include amounts paid to EPCO for the actual direct and indirect costs it incurs to operate our facilities, including the compensation of its employees. Likewise, our general and administrative costs include amounts paid to EPCO for management and other administrative services, including the compensation of its employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of legal or accounting salaries based on estimates of time spent on each entity's business and affairs). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time with respect to the services provided to us by EPCO.

The ASA allows us to participate as a named insured in EPCO's overall insurance program, with the associated premiums and other costs being allocated to us. See Note 18 for additional information regarding our insurance programs.

The following table presents our related party costs and expenses attributable to the ASA with EPCO for the years indicated:

	For the Year Ended December 31,		
	2020	2019	2018
Operating costs and expenses	$ 999.0	$ 1,000.2	$ 948.8
General and administrative expenses	128.9	127.6	124.2
Total costs and expenses	$ 1,127.9	$ 1,127.8	$ 1,073.0

Since the vast majority of such expenses are charged to us on an actual basis (i.e., no mark-up is charged or subsidy is received), we believe that such expenses are representative of what the amounts would have been on a standalone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. The following information summarizes significant related party transactions with our unconsolidated affiliates:

- For the years ended December 31, 2020, 2019 and 2018, we paid Seaway $71.5 million, $194.5 million and $163.2 million, respectively, for pipeline transportation and storage services in connection with our crude oil marketing activities. Revenues from Seaway were $20.2 million, $42.7 million and $74.4 million for the years ended December 31, 2020, 2019 and 2018, respectively.

- For the years ended December 31, 2020, 2019 and 2018, we purchased $51.3 million, $89.2 million and $157.9 million, respectively, of NGLs from VESCO.

- We pay Promix for the transportation, storage and fractionation of NGLs. Expenses with Promix were $23.5 million, $34.8 million and $31.9 million for the years ended December 31, 2020, 2019 and 2018, respectively. In addition, we sell natural gas to Promix for its plant fuel requirements. Revenues from Promix were $6.0 million, $9.1 million and $9.5 million for the years ended December 31, 2020, 2019 and 2018, respectively.

- For the years ended December 31, 2020, 2019 and 2018, we paid Texas Express $29.1 million, $33.5 million and $57.6 million, respectively, for pipeline transportation services.

- For the years ended December 31, 2020, 2019 and 2018, we paid Eagle Ford Crude Oil Pipeline $20.9 million, $36.0 million and $18.5 million, respectively, for pipeline transportation services.

- We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $10.1 million, $9.9 million and $11.6 million for the years ended December 31, 2020, 2019 and 2018, respectively.

Note 16. Income Taxes

Publicly traded partnerships like ours are treated as corporations unless they have 90% or more in "qualifying income" (as that term is defined in the Internal Revenue Code). We satisfied this requirement in each of the years ended December 31, 2020, 2019 and 2018 and, as a result, are not subject to federal income tax. However, our partners are individually responsible for paying federal income tax on their share of our taxable income. Net earnings for financial reporting purposes may differ significantly from taxable income reportable to our unitholders as a result of differences between the tax basis and financial reporting basis of certain assets and liabilities and other factors. We do not have access to information regarding each partner's individual tax basis in our limited partner interests.

The following table presents the components of our consolidated benefit from (provision for) income taxes for the years indicated:

	For the Year Ended December 31,		
	2020	2019	2018
Deferred tax benefit attributable to OTA	$ 155.3	$ –	$ –
Texas Margin Tax	(32.1)	(44.2)	(54.8)
Other	1.1	(1.4)	(5.5)
Benefit from (provision for) income taxes	$ 124.3	$ (45.6)	$ (60.3)

In addition to income tax amounts attributable to OTA (as described below), the provision for income taxes includes our state tax obligations under the Revised Texas Franchise Tax (the "Texas Margin Tax").

Income taxes are accounted for under the asset-and-liability method. Deferred income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

We recognize the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs. Accounting guidance provides that a tax benefit from an uncertain tax position may be recognized when it is more likely than not that the position will be sustained upon examination, including resolutions of any related appeals or litigation processes, based on the technical merits. We did not rely on any uncertain tax positions in recording our income tax-related amounts during the years ended December 31, 2020, 2019 and 2018.

OTA Deferred Tax Liability

On March 5, 2020, the Partnership settled its obligations under the Liquidity Option Agreement (see Note 8) and indirectly assumed OTA's deferred tax liability, which reflects OTA's outside basis difference in the limited partner interests it received from the Partnership in October 2014. Upon settlement of the Liquidity Option, the Liquidity Option liability was effectively replaced by the deferred tax liability of OTA calculated in accordance with ASC 740, *Income Taxes*.

At March 5, 2020, the Liquidity Option liability amount was $511.9 million. Since the book value of the Liquidity Option liability exceeded OTA's estimated deferred tax liability of $439.7 million on that date, we recognized a non-cash benefit in earnings of $72.2 million, which is reflected in the "Benefit from (provision for) income tax" line on our Statement of Consolidated Operations for the year ended December 31, 2020. OTA recognized an additional net, non-cash deferred income tax benefit of $83.1 million primarily due to a decrease in the outside basis difference of its investment in the Partnership attributable to a decline in the market price of the Partnership's common units subsequent to March 5, 2020 through September 30, 2020. In total, earnings for the year ended December 31, 2020 reflect $155.3 million of net deferred income tax benefit attributable to OTA.

On September 30, 2020, OTA exchanged the Partnership common units it owned for non-publicly traded preferred units having a stated value of $1,000 per unit (see Note 8). As a result and beginning September 30, 2020, OTA's deferred tax liability no longer fluctuates due to market price changes in the Partnership's common units. Our subsidiary OTA is a corporation for U.S. federal income tax purposes, and the exchange of common units for preferred units did not constitute a taxable transaction for OTA.

Tabular Disclosures Regarding Income Taxes

Our federal, state and foreign income tax benefit (provision) is summarized below:

	For the Year Ended December 31,		
	2020	2019	2018
Current portion of income tax benefit (provision):			
Federal	$ 2.9	$ 1.3	$ (5.3)
State	(25.6)	(25.7)	(33.1)
Foreign	(0.6)	(1.2)	(0.5)
Total current portion	(23.3)	(25.6)	(38.9)
Deferred portion of income tax benefit (provision):			
Federal	142.0	(1.6)	0.3
State	5.6	(18.5)	(21.7)
Foreign	–	0.1	–
Total deferred portion	147.6	(20.0)	(21.4)
Total benefit from (provision for) income taxes	$ 124.3	$ (45.6)	$ (60.3)

A reconciliation of the benefit from (provision for) income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income before income taxes is as follows:

	For the Year Ended December 31,		
	2020	2019	2018
Pre-Tax Net Book Income ("NBI")	$ 3,761.4	$ 4,732.7	$ 4,298.8
Texas Margin Tax (1)	$ (32.1)	$ (44.2)	$ (54.8)
State income tax benefit (provision), net of federal benefit (2)	9.2	(0.5)	(0.2)
Federal income tax benefit (provision) computed by applying the federal statutory rate to NBI of corporate entities	80.1	(0.9)	(2.1)
Federal benefit attributable to settlement of Liquidity Option (2)	67.8	–	–
Other differences	(0.7)	–	(3.2)
Benefit from (provision for) income taxes	$ 124.3	$ (45.6)	$ (60.3)
Effective income tax rate	3.3%	(1.0)%	(1.4)%

(1) Although the Texas Margin Tax is not considered a state income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers our Texas-sourced revenues and expenses.

(2) The total benefit recognized in income tax expense on March 5, 2020 from settlement of the Liquidity Option was $72.2 million, which is comprised of $4.4 million of state income tax benefit and $67.8 million of federal income tax benefit.

Deferred income taxes are determined based on the temporary differences between the financial statement and income tax bases of assets and liabilities as measured by the enacted tax rates, which will be in effect when these differences reverse.

The following table presents the significant components of deferred tax assets and deferred tax liabilities at the dates indicated:

	December 31,	
	2020	2019
Deferred tax liabilities:		
Attributable to investment in OTA	$ 356.6	$ –
Attributable to property, plant and equipment	106.4	100.2
Attributable to investments in other entities	4.1	3.3
Total deferred tax liabilities	467.1	103.5
Less deferred tax assets:		
Net operating loss carryovers (1)	0.1	0.1
Temporary differences related to Texas Margin Tax	2.3	3.0
Total deferred tax assets	2.4	3.1
Total net deferred tax liabilities	$ 464.7	$ 100.4

(1) These losses expire in various years between 2021 and 2037 and are subject to limitations on their utilization.

Note 17. Commitments and Contingent Liabilities

Litigation

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

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

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

At December 31, 2020 and 2019, our accruals for litigation contingencies were $6.1 million and $0.2 million, respectively, and were recorded in our Consolidated Balance Sheets as a component of "Other current liabilities." Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves uncertainties. In the event the assumptions we use to evaluate these matters change in future periods or new information becomes available, we may be required to record additional accruals. In an effort to mitigate expenses associated with litigation, we may settle legal proceedings out of court.

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 first propane dehydrogenation facility ("PDH 1"). 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 1 project. In December 2015, Enterprise engaged a second contractor, Optimized Process Designs LLC, to complete the construction and installation of PDH 1.

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

Redelivery Commitments

We store natural gas, crude oil, NGLs and certain petrochemical products owned by third parties under various agreements. Under the terms of these agreements, we are generally required to redeliver volumes to the owner on demand. At December 31, 2020, we had approximately 9.9 trillion British thermal units ("TBtus") of natural gas, 19.4 MMBbls of crude oil, and 31.1 MMBbls of NGL and petrochemical products in our custody that were owned by third parties. We maintain insurance coverage in connection with such volumes that is consistent with our exposure. See Note 18 for information regarding insurance matters.

Commitments Under Equity Compensation Plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense attributable to employees who perform management, administrative and operating functions for us. See Notes 13 and 15 for additional information regarding our accounting for equity-based awards and related party information, respectively.

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2020. A description of each type of contractual obligation follows:

	Payment or Settlement due by Period						
Contractual Obligations	Total	2021	2022	2023	2024	2025	Thereafter
Scheduled maturities of debt obligations	$ 30,146.4	$ 1,325.0	$ 1,400.0	$ 1,250.0	$ 850.0	$ 1,150.0	$ 24,171.4
Estimated cash interest payments	$ 28,834.6	$ 1,294.0	$ 1,241.2	$ 1,201.0	$ 1,162.8	$ 1,121.4	$ 22,814.2
Operating lease obligations	$ 460.5	$ 33.7	$ 36.1	$ 33.2	$ 29.9	$ 28.8	$ 298.8
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 155.0	$ 84.6	$ 70.4	$ –	$ –	$ –	$ –
NGLs	$ 3,908.4	$ 685.2	$ 696.8	$ 494.4	$ 436.4	$ 336.8	$ 1,258.8
Crude oil	$ 10,365.7	$ 1,390.1	$ 1,390.1	$ 1,390.1	$ 1,354.9	$ 1,297.2	$ 3,543.3
Petrochemicals and refined products	$ 346.1	$ 100.9	$ 100.9	$ 76.0	$ 68.3	$ –	$ –
Other	$ 25.5	$ 5.8	$ 5.9	$ 6.0	$ 5.1	$ 2.7	$ –
Service payment commitments	$ 278.8	$ 62.0	$ 59.7	$ 42.3	$ 16.1	$ 12.9	$ 85.8

<u>Scheduled Maturities of Debt</u>
We have long-term and short-term payment obligations under debt agreements. Amounts shown in the preceding table represent our scheduled future maturities of debt principal for the years indicated. See Note 7 for additional information regarding our consolidated debt obligations.

<u>Estimated Cash Interest Payments</u>
Our estimated cash payments for interest are based on the principal amount of our consolidated debt obligations outstanding at December 31, 2020, the contractually scheduled maturities of such balances, and the applicable interest rates. Our estimated cash payments for interest are influenced by the long-term maturities of our $2.65 billion in junior subordinated notes (due June 2067 through February 2078). The estimated cash payments assume that (i) the junior subordinated notes are not repaid prior to their respective maturity dates and (ii) the amount of interest paid on the junior subordinated notes is based on either (a) the current fixed interest rate charged or (b) the weighted-average variable rate paid in 2020, as applicable, for each note through the respective maturity date. See Note 7 for information regarding fixed and weighted-average variable interest rates charged in 2020.

<u>Operating Lease Obligations</u>
We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year.

Our significant lease agreements consist of (i) land held pursuant to property leases, (ii) the lease of underground storage caverns for natural gas and NGLs, (iii) the lease of transportation equipment used in our operations and (iv) office space leased from affiliates of EPCO. These lease agreements have terms that range from 5 to 30 years. The agreements to lease office space from affiliates of EPCO and those relating to underground NGL storage caverns we lease from a third party include renewal options that could extend these contracts for up to an additional 20 years. The remainder of our significant lease agreements do not provide for additional renewal terms.

Lease expense is charged to operating costs and expenses on a straight-line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. We are generally required to perform routine maintenance on the underlying leased assets. In addition, certain leases give us the option to make leasehold improvements. Maintenance and repairs of leased assets resulting from our operations are charged to expense as incurred.

The following table presents information regarding operating leases where we are the lessee at December 31, 2020:

Asset Category	ROU Asset Carrying Value (1)	Lease Liability Carrying Value (2)	Weighted-Average Remaining Term	Weighted-Average Discount Rate (3)
Storage and pipeline facilities	$ 128.0	$ 128.7	15 years	4.3%
Transportation equipment	33.5	35.6	3 years	3.5%
Office and warehouse space	170.5	184.3	16 years	3.2%
Total	$ 332.0	$ 348.6		

(1) ROU asset amounts are a component of "Other assets" on our Consolidated Balance Sheet.
(2) At December 31, 2020, lease liabilities of $27.8 million and $320.8 million were included within "Other current liabilities" and "Other liabilities," respectively.
(3) The discount rate for each category of assets represents the weighted average incremental borrowing rate adjusted for collateralization (if the implicit rate is not determinable). In general, the discount rates are based on either (i) information available at the lease commencement date or (ii) January 1, 2019 for leases existing at the adoption date for ASC 842.

In total, our ROU asset and lease liability carrying values increased $121.8 million and $136.6 million, respectively, since December 31, 2019 primarily due to the modification of an office space lease with an affiliate of EPCO in 2020.

In total, operating lease expense was $102.0 million, $106.6 million and $86.4 million for the years ended December 31, 2020, 2019 and 2018, respectively. The following table disaggregates our total operating lease expense for the years indicated:

	For the Year Ended December, 2020	2019
Long-term operating leases:		
Fixed lease expense:		
Non-cash lease expense (amortization of ROU assets)	$ 39.0	$ 42.8
Related accretion expense on lease liability balances	13.0	9.0
Total fixed lease expense	52.0	51.8
Variable lease expense	0.2	6.2
Subtotal operating lease expense	52.2	58.0
Short-term operating leases	49.8	48.6
Total operating lease expense	$ 102.0	$ 106.6

Fixed lease expense is charged to earnings on a straight-line basis over the contractual term, with any variable lease payments expensed as incurred. Short-term operating lease expense is expensed as incurred. Cash paid for operating lease liabilities recorded on our balance sheet was $37.1 million and $48.1 million for the years ended December 31, 2020 and 2019, respectively.

We do not have any significant operating or direct financing leases where we are the lessor. Our operating lease income for the years ended December 31, 2020 and 2019 was $11.4 million and $14.4 million, respectively. We do not have any sales-type leases.

Purchase Obligations

We define purchase obligations as agreements with remaining terms in excess of one year to purchase goods or services that are enforceable and legally binding (i.e., unconditional) on us that specify all significant terms, including (i) fixed or minimum quantities to be purchased, (ii) fixed, minimum or variable price provisions and (iii) the approximate timing of the transactions. We classify our unconditional purchase obligations into the following categories:

- Product purchase commitments – We have long-term product purchase obligations for natural gas, NGLs, crude oil, and petrochemicals and refined products with third party suppliers. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table presents our estimated future payment obligations under these contracts based on the contractual price in each agreement at December 31, 2020 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.

- Service payment commitments – We have long-term commitments to pay service providers, including those attributable to obligations under firm pipeline transportation contracts. Payment obligations vary by contract, but generally represent a price per unit of volume multiplied by a firm transportation volume commitment.

Other Commitments

We are obligated to spend up to an aggregate $270 million over a ten-year period ending in 2025 on specified midstream gathering assets for certain producers utilizing our EFS Midstream System. If constructed, these new assets would be owned by us and be a component of the EFS Midstream System. As of December 31, 2020, we have spent $151 million of the $270 million commitment.

Other Long-Term Liabilities

The following table summarizes the components of "Other long-term liabilities" as presented on our Consolidated Balance Sheets at the dates indicated:

	December 31,	
	2020	2019
Noncurrent portion of AROs (see Note 4)	$ 137.6	$ 126.9
Deferred revenues – non-current portion (see Note 9)	198.2	197.0
Liquidity Option liability	–	509.6
Lease liability – non-current portion	320.8	171.6
Derivative liabilities	17.2	7.3
Other	12.8	20.0
Total	$ 686.6	$ 1,032.4

Liquidity Option

Prior to its settlement on March 5, 2020, the Liquidity Option liability, at any measurement date, represented the fair value of estimated federal and state income taxes that we believe a market participant would assume due to ownership of OTA, including its deferred income tax liabilities. At December 31, 2019 and March 5, 2020, we estimated that our liability under the Liquidity Option Agreement, which was a component of "Other long-term liabilities" on our Consolidated Balance Sheet was $509.6 million and $511.9 million, respectively.

Our valuation estimates for the Liquidity Option liability at December 31, 2019 and March 5, 2020 incorporated several factors not readily observable in the market (i.e., Level 3 inputs) such as: (i) a discount rate of 5.7%; (ii) a blended federal and state income tax rate of approximately 22.8%; (iii) forecasted annual growth rates in our taxable earnings ranging from approximately 0.7% to 2.2%; (iv) allocations of Partnership income to OTA ranging from approximately 2.3% to 2.5%; and (v) the length of time that OTA is in existence following exercise of the option (up to 30 years).

Changes in the fair value of the Liquidity Option liability were recognized in earnings as a component of other expense on our Statements of Consolidated Operations. We recognized $2.3 million of non-cash accretion expense for the period January 1, 2020 to March 5, 2020 attributable to the Liquidity Option liability. Results for the years ended December 31, 2019 and 2018 include $119.6 million and $56.1 million, respectively, of expense attributable to accretion and changes in management estimates regarding inputs to the valuation model. The higher level of expense recognized in 2019 is primarily due to a decrease in the discount factor used in determining the present value of the liability since December 31, 2018. The discount rate is based on a weighted-average cost of capital, which declined over the course of 2019 due to lower U.S. interest rates.

For information regarding settlement of the Liquidity Option, see Note 8.

Note 18. Significant Risks and Uncertainties

Nature of Operations

We operate predominantly in the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, crude oil, and 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, public health emergencies and government regulations affecting prices and production levels.

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

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

Credit Risk

We may incur credit risk to the extent counterparties do not fulfill their obligations to us in connection with our marketing of natural gas, NGLs, crude oil, and petrochemicals and refined products and under long-term contracts with minimum volume commitments or fixed demand charges. Risks of nonpayment and nonperformance by customers are a major consideration in our businesses, and our credit procedures and policies may not be adequate to sufficiently eliminate customer credit risk. Further, adverse economic conditions in our industry, such as those experienced in connection with the COVID-19 pandemic in 2020, may increase the risk of nonpayment and nonperformance by customers, particularly customers that have sub-investment grade credit ratings or small-scale companies. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments, net out agreements and guarantees. However, these procedures and policies do not fully eliminate customer credit risk.

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

In those situations where we are exposed to credit risk in our derivative instrument transactions, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis. Generally, we do not require collateral for such transactions nor do we currently anticipate nonperformance by our material counterparties.

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance may not fully cover every type of damage, interruption or other loss that might occur. If we were to incur a significant loss for which we were not fully insured, it could have a material adverse impact on our financial position, results of operations and cash flows.

In addition, there may be timing differences between amounts we accrue related to property damage expense, amounts we are required to pay in connection with a loss, and amounts we subsequently receive from insurance carriers as reimbursements. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material expenditures not reimbursed by insurance, could reduce our ability to pay distributions to our unitholders and, accordingly, adversely affect the market price of EPD common units.

Involuntary conversions result from the loss of an asset due to some unforeseen event (e.g., destruction due to a fire). Some of these events are covered by insurance, thus resulting in a property damage insurance recovery. Amounts we receive from insurance carriers are net of any deductibles related to the covered event. We record a receivable from insurance to the extent we recognize a loss from an involuntary conversion event and the likelihood of our recovering such loss is deemed probable. To the extent that any of our insurance claim receivables are later judged not probable of recovery (e.g., due to new information), such amounts are expensed. We recognize gains on involuntary conversions when the amount received from insurance exceeds the net book value of the retired assets.

In addition, we do not recognize gains related to insurance recoveries until all contingencies related to such proceeds have been resolved, that is, a non-refundable cash payment is received from the insurance carrier or we have a binding settlement agreement with the carrier that clearly states that a non-refundable payment will be made. To the extent that an asset is rebuilt, the associated expenditures are capitalized, as appropriate, on our Consolidated Balance Sheets and presented as "Capital expenditures" on our Statements of Consolidated Cash Flows.

Under our current insurance program, the standalone deductible for property damage claims is $30 million. We also have business interruption protection; however, such claims must involve physical damage and have a combined loss value in excess of $30 million and the period of interruption must exceed 60 days. With respect to named windstorm claims, the maximum amount of insurance coverage available to us for any single event is $200 million, after applying the appropriate deductibles. A named windstorm is a hurricane, typhoon, tropical storm or cyclone as declared by the U.S. National Weather Service.

Note 19. Supplemental Cash Flow Information

The following table provides information regarding the net effect of changes in our operating accounts and cash payments for interest and income taxes for the years indicated:

	For the Year Ended December 31,		
	2020	2019	2018
Decrease (increase) in:			
Accounts receivable – trade	$ 300.2	$ (1,248.8)	$ 730.2
Accounts receivable – related parties	(0.8)	0.9	(2.3)
Inventories	(1,420.4)	(558.0)	121.4
Prepaid and other current assets	991.4	(69.6)	214.4
Other assets	(79.6)	(63.5)	(9.7)
Increase (decrease) in:			
Accounts payable – trade	11.3	(43.9)	18.3
Accounts payable – related parties	(12.8)	67.8	51.4
Accrued product payables	482.7	1,447.8	(1,132.0)
Accrued interest	23.9	36.1	37.6
Other current liabilities	(992.1)	58.1	(70.9)
Other liabilities	(71.3)	(84.3)	57.8
Net effect of changes in operating accounts	$ (767.5)	$ (457.4)	$ 16.2
Cash payments for interest, net of $115.0, $143.8 and $147.9 capitalized in 2020, 2019 and 2018, respectively	$ 1,201.3	$ 1,080.3	$ 1,017.9
Cash payments for federal and state income taxes	$ 25.1	$ 23.6	$ 15.5

We incurred liabilities for construction in progress that had not been paid at December 31, 2020, 2019 and 2018 of $236.1 million, $432.0 million and $567.6 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Statements of Consolidated Cash Flows.

The following table presents our cash proceeds from asset sales for the years indicated:

	For the Year Ended December 31,		
	2020	2019	2018
Sale of crude oil pipeline system	$ –	$ –	$ 134.9
Other asset sales	12.8	20.6	26.3
Total	$ 12.8	$ 20.6	$ 161.2

The following table presents net gains attributable to asset sales for the years indicated:

	For the Year Ended December 31,		
	2020	2019	2018
Gain on sale of crude oil pipeline system	$ –	$ –	$ 20.6
Net gains attributable to other asset sales	4.4	5.7	8.1
Total	$ 4.4	$ 5.7	$ 28.7