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

FORM 8-K

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

Date of Report (Date of earliest event reported): May 4, 2020

Magellan Midstream Partners, L.P.
(Exact Name of Registrant as Specified in Charter)

Delaware	1-16335	73-1599053
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(IRS Employer Identification No.)

One Williams Center
Tulsa, Oklahoma 74172
(Address of Principal Executive Offices) (Zip Code)

Registrant's telephone number, including area code **(918) 574-7000**

(Former Name or Former Address, if Changed Since Last Report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

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. ☐

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Units	MMP	New York Stock Exchange

Item 8.01. Other Events.

The terms “we”, “us”, “our” and similar language included in this Current Report on Form 8-K refers to Magellan Midstream Partners, L.P., together with its subsidiaries. During first quarter 2020, we completed a reorganization of our reporting segments. This reorganization was effected to reflect changes in the management of our business in conjunction with the sale of three of our marine terminals. Accordingly, effective March 1, 2020, we redesigned our internal management reports to correspond to this new organizational structure, resulting in changes to our reporting segments. Our new reporting segments are as follows:

- Refined products; and
- Crude oil.

A summary of each of our current reporting segments follows:

- Our refined products segment is comprised of our approximately 9,800-mile refined products pipeline system with 53 connected terminals, as well as 25 independent terminals not connected to our pipeline system and five marine terminals (one of which is owned through a joint venture).

- Our crude oil segment is comprised of approximately 2,200 miles of crude oil pipelines, a condensate splitter and 37 million barrels of aggregate storage capacity, of which approximately 25 million barrels are used for contract storage. Approximately 1,000 miles of these pipelines, the condensate splitter and 30 million barrels of this storage capacity (including 22 million barrels used for contract storage) are wholly-owned, with the remainder owned through joint ventures.

Exhibit 99.1 hereto updates the following information contained in our Annual Report on Form 10-K for the year ended December 31, 2019 filed with the Securities and Exchange Commission on February 18, 2020 ("2019 10-K") to reflect these changes in reportable segments: (i) Item 1. Business; (ii) Item 6. Selected Financial Data; (iii) Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A"); and (iv) Item 8. Financial Statements and Supplementary Data.

The recast items of the Form 10-K described above continue to speak as of the date of the filing of our 2019 10-K report with the SEC and have not been updated for events or developments that occurred subsequent to such filing, other than the change in our segment reporting and certain other events disclosed in Note 19 - Subsequent Events within Item 8 of Exhibit 99.1. More current information about us and our business is contained in our Quarterly Report on Form 10-Q for the period ended March 31, 2020, and the information in this Current Report, including the exhibits, should be read in conjunction with such Quarterly Report and other filings we make with the SEC.

Item 9.01. Financial Statements and Exhibits.

Exhibit 23.1	Consent of Independent Registered Public Accounting Firm.
Exhibit 99.1	Item 1—*Business*, Item 6—*Selected Financial Data*, Item 7—*Management's Discussion and Analysis of Financial Condition and Results of Operations* and

	Item 8—*Financial Statements and Supplementary Data* from our 2019 10-K, updated to reflect revised operating segment information.
Exhibit 101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
Exhibit 101.SCH	XBRL Taxonomy Extension Schema Document.
Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
Exhibit 104	Cover Page Interactive Data File (embedded within the Inline XBRL document).

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Magellan Midstream Partners, L.P.

By: **Magellan GP, LLC,**
its general partner

Date: May 4, 2020

By: /s/ Jeff Holman
Name: Jeff Holman
Title: Senior Vice President, Chief Financial Officer and Treasurer

EXHIBIT 99.1

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Forward-Looking Statements

Except for statements of historical fact, all statements in this Exhibit 99.1 on Form 8-K constitute forward-looking statements within the meaning of the federal securities laws. Forward-looking statements may be identified by words like “anticipates,” “believes,” “continue,” “could,” “estimates,” “expects,” “forecasts,” “goal,” “guidance,” “intends,” “may,” “might,” “plans,” “potential,” “projected,” “scheduled,” “should,” “will” and other similar expressions. The absence of such words or expressions does not necessarily mean the statements are not forward-looking. Although we believe our forward-looking statements are reasonable, statements made regarding future results are not guarantees of future performance and are subject to numerous assumptions, uncertainties and risks that are difficult to predict, including those described in Part I, Item 1A – *Risk Factors* in our Annual Report on Form 10-K for the year ended December 31, 2019. Actual outcomes and results may be materially different from the results stated or implied in such forward-looking statements included in this report. You should not put any undue reliance on any forward-looking statement.

The following are among the important factors that could cause future results to differ materially from any expected, projected, forecasted, estimated or budgeted amounts, events or circumstances we have discussed in this report:

- overall demand for refined products, crude oil and liquefied petroleum gases;
- price fluctuations for refined products, crude oil and liquefied petroleum gases and expectations about future prices for these products;
- changes in the production of crude oil in the basins served by our pipelines;
- changes in general economic conditions, interest rates and price levels;
- changes in the financial condition of our customers, vendors, derivatives counterparties, lenders or joint venture co-owners;
- our ability to secure financing in the credit and capital markets in amounts and on terms that will allow us to execute our business strategy, refinance our existing obligations when due and maintain adequate liquidity;
- development of alternative energy sources, including but not limited to natural gas, solar power, wind power, electric and battery-powered engines and geothermal energy, increased use of biofuels such as ethanol and biodiesel, increased conservation or fuel efficiency, increased use of electric vehicles, as well as regulatory developments or other trends that could affect demand for our services;
- changes in population in the markets served by our refined products pipeline system and changes in consumer preferences, driving patterns or rates of automobile ownership;
- changes in the product quality, throughput or interruption in service of refined products or crude oil pipelines owned and operated by third parties and connected to our assets;
- changes in demand for transportation or storage in our refined products or crude oil segments;
- changes in supply and demand patterns for our facilities due to geopolitical events, the activities of the Organization of the Petroleum Exporting Countries, changes in U.S. trade policies or in laws governing the importing and exporting of petroleum products, technological developments or other factors;
- our ability to manage interest rate and commodity price exposures;
- changes in our tariff rates or other terms of service implemented by the Federal Energy Regulatory Commission (“FERC”) or state regulatory agencies;
- shut-downs or cutbacks at refineries, oil wells, petrochemical plants or other customers or businesses that use or supply our services;
- the effect of weather patterns and other natural phenomena, including climate change, on our operations and demand for our services;
- an increase in the competition our operations encounter, including the effects of capacity over-build in the areas where we operate;
- the occurrence of natural disasters, terrorism, sabotage, protests or activism, operational hazards, equipment failures, system failures or unforeseen interruptions;
- our ability to obtain adequate levels of insurance at a reasonable cost, and the potential for losses to exceed the insurance coverage we do obtain;

- the treatment of us as a corporation for federal or state income tax purposes or if we become subject to significant forms of other taxation or more aggressive enforcement or increased assessments under existing forms of taxation;
- our ability to identify expansion projects with acceptable expected returns or to complete identified expansion projects on time and at projected costs;
- our ability to make and integrate accretive acquisitions and joint ventures and successfully execute our business strategy;
- uncertainty of estimates, including accruals and costs of environmental remediation;
- our ability to cooperate with and rely on our joint venture co-owners;
- actions by rating agencies concerning our credit ratings;
- our ability to timely obtain and maintain all necessary approvals, consents and permits required to operate our existing assets and to construct, acquire and operate any new or modified assets;
- our ability to promptly obtain all necessary services, materials, labor, supplies and rights-of-way required for construction of our growth projects, and to complete construction without significant delays, disputes or cost overruns;
- risks inherent in the use and security of information systems in our business and implementation of new software and hardware;
- changes in laws and regulations or the interpretations of such laws that govern our gas liquids blending activities, including the potential applicability of the Carmack Amendment, which broadly covers claims for damage or loss incurred to goods transported by a carrier in interstate commerce, to such activities, or changes regarding product quality specifications or renewable fuel obligations that impact our ability to produce gasoline volumes through our gas liquids blending activities or that require significant capital outlays for compliance;
- changes in laws and regulations to which we or our customers are or could become subject, including tax withholding requirements, safety, security, employment, hydraulic fracturing, derivatives transactions, trade and environmental laws and regulations, including laws and regulations designed to address climate change;
- the cost and effects of legal and administrative claims and proceedings against us, our subsidiaries or our joint ventures;
- the amount of our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- the effect of changes in accounting policies;
- the potential that our internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful;
- the ability and intent of our customers, vendors, lenders, joint venture co-owners or other third parties to perform on their contractual obligations to us;
- petroleum product supply disruptions;
- global and domestic repercussions from terrorist activities, including cyber attacks, and the government’s response thereto; and
- other factors and uncertainties inherent in the transportation, storage and distribution of petroleum products and the operation, acquisition and construction of assets related to such activities.

This list of important factors is not exhaustive. The forward-looking statements in this report speak only as of the date hereof, and we undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events, changes in assumptions or otherwise, unless required by law.

MAGELLAN MIDSTREAM PARTNERS, L.P.

PART I

Item 1. *Business*

(a) General Development of Business

Unless indicated otherwise, the terms "our," "we," "us" and similar language refer to Magellan Midstream Partners, L.P. together with its subsidiaries. Magellan Midstream Partners, L.P. is a Delaware limited partnership formed in August 2000, and its common units are traded on the New York Stock Exchange under the ticker symbol "MMP." Magellan GP, LLC, a wholly-owned Delaware limited liability company, serves as its general partner.

(b) [Reserved.]

(c) Narrative Description of Business

During first quarter 2020, we completed a reorganization of our reportable segments. This reorganization was effected to reflect changes in the management of our business in conjunction with the sale of three of our marine terminals. Five of our marine terminals, including the terminals sold during first quarter, were combined with our refined products segment and one terminal was combined with our crude oil segment based on the predominant types of product stored at the facilities. Accordingly, we have restated our segment disclosures for all previous periods included in this report.

We are principally engaged in the transportation, storage and distribution of refined petroleum products and crude oil. As of December 31, 2019, our asset portfolio consisted of:

- our refined products segment, comprised of our approximately 9,800-mile refined products pipeline system with 53 terminals as well as 25 independent terminals not connected to our pipeline system and five marine terminals (one of which is owned through a joint venture); and

- our crude oil segment, comprised of approximately 2,200 miles of crude oil pipelines, a condensate splitter and 37 million barrels of aggregate storage capacity, of which approximately 25 million barrels are used for contract storage. Approximately 1,000 miles of these pipelines, the condensate splitter and 30 million barrels of this storage capacity (including 22 million barrels used for contract storage) are wholly-owned, with the remainder owned through joint ventures.

Industry Background

The United States ("U.S.") petroleum products transportation and distribution system links sources of crude oil supply with refineries and ultimately with end users of petroleum products. This system is comprised of a network of pipelines, terminals, storage facilities, waterborne vessels, railcars and trucks. For transportation of petroleum products, pipelines are generally the most reliable, lowest cost and safest alternative for intermediate and long-haul movements between different markets. Throughout the distribution system, terminals play a key role in facilitating product movements by providing storage, distribution, blending and other ancillary services.

Terminology common in our industry includes the following terms, which describe products that we transport, store, distribute or otherwise handle through our petroleum pipelines and terminals:

- *refined products* are the output from crude oil refineries that are primarily used as fuels by consumers. Refined products include gasoline, diesel fuel, aviation fuel, kerosene and heating oil. Diesel fuel, kerosene and heating oil are also referred to as distillates;

- *transmix* is a mixture of refined products that forms when transported in pipelines. Transmix is fractionated and blended into usable refined products;

- *liquefied petroleum gases or LPGs* are liquids produced as by-products of the crude oil refining process and in connection with natural gas production. LPGs include butane and propane;

- *blendstocks* are products blended with refined products to change or enhance their characteristics such as increasing a gasoline's octane or oxygen content. Blendstocks include alkylates, oxygenates and natural gasoline;

- *heavy oils and feedstocks* are products used as burner fuels or feedstocks for further processing by refineries and petrochemical facilities. Heavy oils and feedstocks include No. 6 fuel oil and vacuum gas oil;

- *crude oil,* which includes condensate, is a naturally occurring unrefined petroleum product recovered from underground that is used as feedstock by refineries, splitters and petrochemical facilities; and

- *biofuels,* such as ethanol and biodiesel, are fuels derived from living materials and typically blended with other refined products as required by government mandates.

We use the term *petroleum products* to describe any, or a combination, of the above-noted products.

Description of Our Businesses

REFINED PRODUCTS

Our refined products segment consists of our refined products pipeline system, our independent terminals and five marine terminals. Our refined products pipeline system is the longest common carrier pipeline system for refined products and LPGs in the U.S., extending approximately 9,800 miles from the Texas Gulf Coast and covering a 15-state area across the central U.S. The system includes approximately 46 million barrels of aggregate usable storage capacity at 53 connected terminals. Our network of independent terminals includes 25 refined products terminals with 6 million barrels of storage located primarily in the southeastern U.S. and connected to third-party common carrier interstate pipelines, including the Colonial and Plantation pipelines. Our Galena Park marine terminal is located along the Houston Ship Channel and has 13 million barrels of wholly owned storage capacity and one million barrels of storage capacity that we own through a joint venture. Our Pasadena marine terminal joint venture is also located along the Houston Ship Channel and has storage capacity of five million barrels. In first quarter 2020, we sold our New Haven, Marrero and Wilmington terminals, which had a combined storage capacity of approximately 10 million barrels.

Our refined products segment accounted for the following percentages of our consolidated revenue, operating margin and total assets:

	Year Ended December 31,		
	2017	2018	2019
Percent of consolidated revenue	79%	78%	76%
Percent of consolidated operating margin	66%	65%	62%
Percent of consolidated total assets	58%	61%	64%

See Note 3—*Segment Disclosures* in the accompanying consolidated financial statements in Item 8 for a description of the non-generally accepted accounting principles ("GAAP") measure of operating margin and additional financial information about our refined products segment.

Operations. *Transportation, Terminalling and Ancillary Services.* During 2019, approximately 65% of the refined products segment's revenue (excluding product sales revenue) was generated from transportation tariffs on volumes shipped on our refined products pipeline system. These transportation tariffs vary depending upon where the product originates, where ultimate delivery occurs and any applicable discounts. All transportation rates and discounts are in published tariffs filed with the FERC or appropriate state agency. Included as part of these tariffs are charges for terminalling and storage of products at 31 of our pipeline system's 53 connected terminals. Revenue from terminalling and storage at the other 22 terminals on our refined products pipeline system is derived from privately negotiated rates. Under our tariffs, we are allowed to deduct prescribed quantities of the products our shippers transport on our pipelines, which are commonly referred to as "tender deductions," to compensate us for lost product during shipment due to metering inaccuracies, intermingling of products between batches (transmix), evaporation or other events that result in volume shortages during the shipment process. In return for these tender deductions, our customers receive a guaranteed delivery of the gross volume of products they ship with us, less the amount of our tender deductions, irrespective of the actual amount of product shortages we incur during the shipment process.

In 2019, the products transported on our refined products pipeline system were comprised of 54% gasoline, 36% distillates and 10% aviation fuel and LPGs. The operating statistics below reflect our refined products pipeline system's operations for the periods indicated:

	Year Ended December 31,		
	2017	**2018**	**2019**
Shipments (million barrels):			
Gasoline	295.5	286.9	280.5
Distillates	166.2	181.7	184.6
Aviation fuel	26.5	31.0	41.1
LPGs	9.9	11.0	9.7
Total shipments	498.1	510.6	515.9

Our refined products pipeline system generates additional revenue from providing pipeline capacity and tank storage services, as well as providing services such as terminalling, ethanol and biodiesel unloading and loading, additive injection, custom blending, laboratory testing and data services to shippers, which are performed under a mix of "as needed," monthly and long-term agreements.

Our independent terminals generate revenue primarily by charging fees based on the amount of product delivered through our facilities and from ancillary services such as additive injections and ethanol blending.

Our marine terminals generate revenue primarily by providing storage and related services.

Commodity-Related Activities. Substantially all of the transportation, throughput and storage services we provide are for third parties, and we do not take title to their products. We do take title of products related to tender deductions, product overages and our gas liquids blending and fractionation activities on our refined products pipeline system. The sales of these products generate product sales revenue.

Our gas liquids blending activity primarily involves purchasing butane and blending it into gasoline, which creates additional gasoline available for us to sell. This activity is limited by seasonal changes in gasoline vapor pressure specification requirements and by the varying quality of the gasoline products delivered to us. When the differential between the cost of gas liquids and the price of gasoline fluctuates, the product margin we earn from these activities is impacted. We hedge the economic margin from this blending activity by entering into forward physical or exchange-traded gasoline futures contracts at the time we purchase the related gas liquids. These blending activities accounted for approximately 76% of the total product margin for the refined products segment during 2019.

We also operate three fractionators along our pipeline system that separate transmix into gasoline and diesel. In addition to fractionating the transmix that results from our pipeline operations, we also purchase and fractionate transmix from third parties and sell the resulting refined products.

Product margin from commodity-related activities in our refined products segment was $128.9 million, $220.3 million and $116.6 million for the years ended December 31, 2017, 2018 and 2019, respectively. The amount of margin we earn from these activities and related hedges fluctuates with changes in petroleum prices (see Note 13–*Derivative Financial Instruments* to the consolidated financial statements included in Item 8 of this report for further information regarding our hedging activities). Product margin is a non-GAAP financial measure, but its components are determined in accordance with GAAP. Product margin, which is calculated as product sales revenue less cost of product sales, is used by management to evaluate the profitability of our commodity-related activities. The components of product margin included in operating profit, the nearest GAAP measurement, are provided in Note 3—*Segment Disclosures* to the consolidated financial statements included in Item 8 of this report.

Joint Venture Activities. We own a 50% interest in Powder Springs Logistics, LLC ("Powder Springs"), which was formed to construct and operate a gas liquids blending system near Atlanta, Georgia. Powder Springs began operations in 2017.

We own a 50% interest in Texas Frontera, which owns approximately one million barrels of storage at our Galena Park terminal. We serve as operator of the Texas Frontera assets.

We own a 50% interest in MVP, which owns a refined products marine storage terminal along the Houston Ship Channel in Pasadena, Texas. The facility began operations in January 2019 with one million barrels of storage and a proprietary ship dock. Construction of an additional four million barrels of storage, truck loading facilities and a second ship dock was substantially complete in late 2019. We serve as operator of the MVP assets.

Markets and Competition. Shipments originate on our refined products pipeline system from direct connections to refineries or through interconnections with other pipelines or terminals for transportation and ultimate distribution to retail gasoline stations, truck stops, railroads, airports and other end users. Through direct refinery connections and interconnections with other interstate pipelines, our refined products system can access approximately 45% of U.S. refining capacity, and in particular is well-connected to Texas Gulf Coast and Mid-Continent refineries. As a result of its extensive connections to multiple refining regions, our pipeline system is well positioned to accommodate demand or supply shifts that may occur.

Our system is dependent on the ability of refiners and marketers to meet the demand for refined products in the markets they serve through shipments on our pipeline system. Demand for refined products is influenced by many factors, including driving patterns and consumer preferences, economic conditions, population changes, government regulations, changes in vehicle fuel efficiency and development of alternative energy sources. The demand for refined products in the market areas served by our pipeline system has historically been stable. We generally rely on recent historical trends on our system and third-party forecasts in assessing future refined products demand, and those forecasts vary both by forecaster and by product. While increases in vehicle efficiency and more widespread penetration of electric vehicles are generally expected to reduce demand for gasoline over time, distillate demand is expected to be less affected, while demand for aviation fuel and LPGs is expected to grow. Projections published by the Energy Information Administration in January 2020 suggest that overall demand for refined products in the market areas served by our pipeline system, primarily the West North Central and West South Central census districts, will decline approximately 0.5% annually over the next ten years.

In 2019, approximately 62% of the products transported on our refined products pipeline system originated from 18 direct refinery connections and 38% originated from connections with other pipelines or terminals. Our system is directly connected to and receives product from the following refineries:

Major Origins—Refineries (Listed Alphabetically)

Company	Refinery Location
CHS	McPherson, KS
CVR Energy	Coffeyville, KS
CVR Energy	Wynnewood, OK
Flint Hills Resources	Pine Bend, MN
HollyFrontier	El Dorado, KS
HollyFrontier	Tulsa, OK
HollyFrontier	Cheyenne, WY
Husky Energy	Superior, WI
Marathon	St. Paul, MN
Marathon	El Paso, TX
Marathon	Galveston Bay, TX
Par Pacific	Newcastle, WY
Phillips 66	Ponca City, OK
Sinclair	Evansville, WY
Suncor Energy	Commerce City, CO
Valero	Ardmore, OK
Valero	Houston, TX
Valero	Texas City, TX

Our system is also supplied by connections to multiple pipelines and terminals, including those shown in the table below:

Major Origins—Pipelines and Terminals (Listed Alphabetically)

Pipeline/Terminal	Connection Location	Source of Product
BP	Manhattan, IL	Whiting, IN refinery
CHS	Fargo, ND	Laurel, MT refinery
Explorer	Mt. Vernon, MO; Glenpool, OK; Dallas, TX; East Houston, TX; Pasadena, TX	Various Gulf Coast refineries
Holly Energy Partners	Duncan, OK; El Paso, TX	Big Spring, TX refinery, Artesia, NM refinery
Kinder Morgan	Galena Park and Pasadena, TX	Various Gulf Coast refineries and imports
Magellan	Galena Park, TX	Various Gulf Coast refineries and imports
Mid-America (Enterprise)	El Dorado, KS	Conway, KS storage
NuStar Energy	Denver, CO; El Dorado, KS; Minneapolis, MN	Various OK & KS refineries, Mandan, ND refinery, McKee, TX refinery
ONEOK	Des Moines, IA; Wayne, IL; Plattsburg, MO	Bushton, KS storage and Chicago, IL area refineries
Phillips 66	Denver, CO; Kansas City, KS; Pasadena, TX; Casper, WY	Borger, TX refinery, various Billings, MT area refineries, Sweeney, TX refinery
Shell	East Houston, TX	Deer Park, TX refinery

In certain markets, barge, truck or rail provide an alternative source for transporting refined products; however, pipelines are generally the most reliable, lowest cost and safest alternative for refined products movements between different markets. As a result, our pipeline system's most significant competitors are other pipelines that serve the same markets.

Competition with other pipeline systems is based primarily on transportation charges, quality of customer service, proximity to end users and longstanding customer relationships. However, given the different supply sources on each pipeline, commodity prices at either the origin or destination point on a pipeline may outweigh transportation costs when customers choose which pipeline to use.

Another form of competition for pipelines is the use of exchange agreements among shippers. Under these agreements, a potential shipper agrees to supply a market near its refinery or terminal in exchange for receiving supply from another refinery or terminal in a different market. These agreements allow the two parties to reduce or eliminate the volumes transported and, therefore, the transportation fees paid to us. We compete with these alternatives through price incentives and through long-term commercial arrangements with potential exchange partners.

Government mandates increasingly require the use of renewable fuels, particularly ethanol. Due to technical and operational concerns, pipelines have generally not shipped ethanol, and most ethanol is transported by railroad, truck or barge. The increased use of ethanol has and will continue to compete with shipments on our pipeline system. However, our terminals have the necessary infrastructure to blend ethanol with refined products, and we earn revenue for these services.

Our independent terminals receive product primarily from the interstate pipelines to which they are connected and serve the retail, industrial and commercial sales markets along those pipelines. Demand for our services is driven primarily by end user demand for refined products in those markets. Our terminals compete with other independent terminal operators as well as integrated oil companies on the basis of terminal location and versatility, services provided and price.

Our marine storage terminals compete with other terminals with respect to location, price, versatility and services provided. The competition primarily comes from integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.

Customers and Contracts. Our refined products pipeline system provides services to several different types of customers, including refiners, wholesalers, retailers, traders, railroads, airlines and regional farm cooperatives. End markets for refined products deliveries are primarily retail gasoline stations, truck stops, farm cooperatives, railroad fueling depots, military bases and commercial airports. LPG shippers include wholesalers and retailers that, in turn, sell to commercial, industrial, agricultural and residential heating customers. Published tariffs serve as contracts, and shippers nominate the volume to be shipped up to a month in advance. In addition, we enter into agreements with shippers that commonly result in payment, volume or term commitments in exchange for reduced tariff rates or expansion capital spending on our part. For 2019, approximately 40% of the shipments on our pipeline system were subject to these supplemental agreements. The average remaining life of these agreements was approximately three years as of December 31, 2019. While many of these supplemental agreements do not represent guaranteed volumes, they do reflect a significant level of shipper commitment to our refined products pipeline system.

For the year ended December 31, 2019, our refined products pipeline system had approximately 65 transportation customers. The top 10 shippers included independent refining companies, integrated oil companies, farm cooperatives and traders. Revenue attributable to these top 10 shippers for the year ended December 31, 2019 represented 34% of total revenue for our refined products segment and 51% of revenue excluding product sales.

Customers of our independent terminals include refiners, retailers, wholesalers and traders. Contracts vary in term and commitment and typically renew automatically, unless the customer elects to terminate, at the end of each contract period.

Customers of our marine terminals include refiners, chemical companies, marketers and traders. As of December 31, 2019, approximately 85% of our usable storage capacity, including the storage capacity of our joint ventures, and excluding the storage capacity of the three marine terminals we sold in first quarter 2020, was under contract, with an average remaining life of approximately three years. These contracts obligate the customer to pay for terminal capacity reserved even if not used by the customer.

Product sales are primarily to trading and marketing companies active in the markets we serve. These sales agreements are generally short-term in nature.

CRUDE OIL

Our crude oil segment is comprised of approximately 2,200 miles of crude oil pipelines, a condensate splitter and storage facilities with an aggregate storage capacity of approximately 37 million barrels, of which 25 million barrels are used for contract storage. Approximately 1,000 miles of these pipelines, the condensate splitter and 30 million barrels of this storage capacity (including 22 million barrels used for contract storage) are wholly-owned, with the remainder owned through joint ventures.

The joint ventures in our crude oil segment are BridgeTex Pipeline Company, LLC (“BridgeTex”), Double Eagle Pipeline LLC (“Double Eagle”), HoustonLink Pipeline Company, LLC (“HoustonLink”), Saddlehorn Pipeline Company, LLC (“Saddlehorn”) and Seabrook Logistics, LLC (“Seabrook”).

Our crude oil segment accounted for the following percentages of our consolidated revenue, operating margin and total assets:

	Year Ended December 31,		
	2017	2018	2019
Percent of consolidated revenue	21%	22%	24%
Percent of consolidated operating margin	34%	35%	37%
Percent of consolidated total assets	39%	36%	34%

See Note 3–*Segment Disclosures* in the accompanying consolidated financial statements in Item 8 for additional financial information about our crude oil segment.

Operations. Our crude oil assets are strategically located to serve crude oil supply, trading and demand centers. Revenue is generated primarily through transportation tariffs on our crude oil pipelines, storage fees from our crude oil terminals, providing pipeline capacity and tolling fees from our condensate splitter. In addition, we earn revenue for ancillary services including terminal throughput fees. We generally do not take title to the products we ship or store for our crude oil customers. Our tariffs provide for tender deductions to compensate us for lost product during shipment due to metering inaccuracies, evaporation or other events that result in volume losses during the shipment process, and we take title to these products. We also take title to volumes shipped in connection with our crude oil marketing activities.

Our 450-mile Longhorn pipeline has the capacity to transport approximately 275,000 barrels per day ("bpd") of crude oil from the Permian Basin in West Texas to Houston, Texas. Shipments originate on the Longhorn pipeline in Crane, Barnhart or Midland, Texas via trucks or interconnections with crude oil gathering systems owned by third parties and are delivered to our terminal at East Houston or to various points on the Houston Ship Channel, including multiple refineries connected to our Houston distribution system.

Our East Houston terminal includes approximately nine million barrels of crude oil storage, with approximately five million barrels used for contract storage and four million barrels dedicated to the operation of the Longhorn and BridgeTex pipelines. (See discussion of our BridgeTex joint venture under *Joint Venture Activities* below.) Our East Houston terminal is also connected to our Houston distribution system and to third-party pipelines, including the Zydeco pipeline. Argus' West Texas Intermediate ("WTI") Houston price assessment is based on trades at the terminal, and the terminal is the delivery point for the Permian WTI Crude Oil futures contract traded on the Intercontinental Exchange.

Our Houston distribution system consists of more than 100 miles of pipeline that connect our East Houston terminal through several interchanges to various points, including multiple refineries throughout the Houston area and crude oil import and export facilities, including through the facility owned by Seabrook discussed below. In addition, it is directly connected to other third-party crude oil pipelines providing us access to crude oil from the Permian and Eagle Ford basins, the strategic crude oil trading hub in Cushing, Oklahoma and crude oil imports.

Our Cushing terminal consists of approximately 13 million barrels of crude oil storage, all of which is used for contract storage. The facility primarily receives and distributes crude oil via the multiple common carrier pipelines that terminate in and originate from the Cushing crude oil trading hub, including the pipeline owned by our Saddlehorn joint venture discussed below, as well as short-haul pipeline connections with neighboring crude oil terminals.

We own approximately 400 miles of pipeline in Kansas and Oklahoma used for crude oil service. A portion of these pipelines is leased to third parties, and we earn revenue from these pipeline segments for capacity leased even if not used by the customers.

Our Corpus Christi terminal includes approximately four million barrels of storage, with a portion used for contract storage and a portion used in conjunction with our Double Eagle joint venture discussed below. This terminal receives product primarily from trucks, barges and pipelines that connect to our terminal for further distribution to end users by trucks, pipeline or waterborne vessels. Our 50,000 bpd condensate splitter with approximately two million barrels of related storage is also located at our terminal in Corpus Christi.

Crude Oil Marketing Activities. Our crude oil marketing activities primarily involve purchasing and selling crude oil to be shipped on our Texas crude oil pipelines to facilitate intrastate shipments and maximize profitability on our crude oil pipeline assets. The revenues from these activities are reflected as product sales revenue in our consolidated statements of income. The product margin we earn from these activities is primarily based on the differential in market prices for crude oil between our origin and destination points.

Joint Venture Activities. We own a 30% interest in BridgeTex, a joint venture with an affiliate of Plains All American Pipeline, L.P. ("Plains") and an affiliate of OMERS Infrastructure Management Inc. BridgeTex owns an approximately 400-mile pipeline currently capable of transporting up to 440,000 bpd of Permian Basin crude oil from Midland and Colorado City, Texas to our East Houston terminal. We serve as operator of the BridgeTex pipeline. We also have a long-term lease agreement with BridgeTex to provide it with capacity on our Houston distribution system.

We own a 50% interest in Double Eagle, a joint venture with an affiliate of Kinder Morgan, Inc. ("Kinder") that transports condensate from the Eagle Ford basin in South Texas via an approximately 200-mile pipeline to our terminal in Corpus Christi or to an inter-connecting pipeline that transports product to the Houston area. An affiliate of Kinder serves as the operator of the Double Eagle pipeline. We have entered into a terminal throughput agreement with Double Eagle.

We own a 50% interest in HoustonLink, a joint venture with an affiliate of TC Energy Corporation ("TC Energy"). HoustonLink owns a crude oil pipeline connecting TC Energy's Houston terminal, which is a termination point for TC Energy's Marketlink Pipeline, to our nearby East Houston terminal. We serve as operator of the HoustonLink pipeline.

As of December 31, 2019, we owned a 40% interest in Saddlehorn, a joint venture with an affiliate of Plains and an affiliate of Western Midstream Partners, LP. Saddlehorn owns an undivided joint interest in an approximately 600-mile pipeline, which delivers various grades of crude oil from the DJ Basin as well as other Rocky Mountain production regions to storage facilities in Cushing, including our Cushing terminal. Saddlehorn currently has the capacity to deliver up to 190,000 bpd of crude oil, which is expected to increase to 290,000 bpd upon the completion of an expansion project in late 2020. We serve as operator of and have also entered into storage contracts with Saddlehorn. In February 2020, we and Plains each sold a 10% interest in Saddlehorn to an affiliate of Black Diamond Gathering LLC (see *Item 7, Management's Discussion and Analysis – Recent Developments* for more information regarding the sale).

We own a 50% interest in Seabrook, a joint venture with an affiliate of LBC Tank Terminals, LLC ("LBC"). Seabrook owns approximately three million barrels of crude oil storage (two million barrels of which is used for contract storage) located in Seabrook, Texas, a pipeline connecting Seabrook's storage facilities to an existing third-party pipeline that connects to a Houston-area refinery and another pipeline connecting its facility to our Houston distribution system. LBC serves as operator of the Seabrook terminal, while we serve as operator of the Seabrook pipelines. In addition, we have a long-term lease agreement with Seabrook that is utilized to provide our customers with crude oil storage capacity and dock access for crude oil imports and exports on the Texas Gulf Coast.

Markets and Competition. Market conditions experienced by our crude oil pipelines vary significantly by location. The Longhorn and BridgeTex pipelines deliver Permian Basin production to trading and demand centers in the Houston area, and consequently depend on the level of production in the Permian Basin for supply. Demand for shipments to the Houston area is driven primarily by the utilization of West Texas crude oil by Gulf Coast refineries and the price for crude oil on the Gulf Coast relative to its price in alternative markets, including export markets. Permian Basin production may vary based on numerous factors including overall crude oil prices and changes in costs of production, while Gulf Coast demand for Permian Basin production may change based on relative prices for competing crude oil or changes by refineries to their crude oil processing slates, as well as by overall domestic and international demand for petroleum products. The Longhorn and BridgeTex pipelines compete with alternative outlets for Permian Basin production, including pipelines that transport crude oil to the Cushing crude oil trading hub as well as other pipelines that currently transport or new pipelines that may transport Permian Basin crude to the Gulf Coast. These pipelines also compete with truck and rail alternatives for Permian Basin barrels. Further, these pipelines indirectly compete with other alternatives for delivering similar quality crude oil to the Gulf Coast, including pipelines from other producing regions such as the Mid-Continent, Bakken, Eagle Ford or Gulf of Mexico, as well as waterborne imports. Competition is based primarily on tariff rates, proximity to both supply sources and demand centers, connectivity, service offerings, crude quality and customer relationships.

Volumes on our Houston distribution system are driven by our customers' demand for distribution of crude oil between our system's various connections and as a result are affected in part by changes in origins and destinations of crude oil processed in or distributed through the Gulf Coast region. Our HoustonLink and Seabrook joint ventures offer our customers additional pipeline connectivity, crude oil storage and import and export capabilities in the Houston area. Our Houston distribution system competes with other distribution facilities in the Houston area based primarily on tariff rates, connectivity to supply sources and demand centers, customer service and customer relationships.

Our crude oil storage facilities in Cushing serve customers who value Cushing's location as an interchange point for numerous interstate pipelines, including Saddlehorn, and its status as a crude oil trading hub. Demand for crude oil storage in Cushing could be affected by changes in crude oil pipeline flows that change the volume of crude oil that flows through or is stored in Cushing, as well as by developments of alternative trading hubs that reduce Cushing's relative importance. In addition, demand for our storage services in Cushing could be affected by crude oil price volatility or price structures or by regulatory or financial conditions that affect the ability of our customers to store or trade crude oil. We compete in Cushing with numerous other storage providers, with competition based on a combination of connectivity, storage rates and other terms, customer service and customer relationships.

The Double Eagle pipeline depends on condensate production from the Eagle Ford basin for its supply and competes primarily with other pipelines and supply alternatives that are capable of transporting condensate from the Eagle Ford production area. Competition is based primarily on tariff rates, connectivity, customer service and customer relationships. The demand for Double Eagle's services could be affected by changes in Eagle Ford condensate production or changes in demand for different grades of condensate. Eagle Ford production may vary based on numerous factors including overall crude oil prices and changes in costs of production. Demand for our storage at Corpus Christi is subject to similar market conditions and competitive forces.

Our condensate splitter at our Corpus Christi terminal depends on condensate production and overall demand for products derived from condensate. Our splitter competes with other facilities in the Gulf Coast region including other splitters and refineries, as well as export alternatives.

The Saddlehorn pipeline depends on crude oil production primarily from the DJ Basin and broader Rocky Mountain region for its supply and competes primarily with other pipelines and supply alternatives that are capable of transporting crude oil from the DJ Basin and Rocky Mountain production area. Competition is based primarily on tariff rates, connectivity, customer service and customer relationships. The demand for Saddlehorn's services could be affected by changes in DJ Basin crude oil production and additional investment in competing transportation alternatives out of the basin, as well as the status of Cushing as a crude oil trading hub. DJ Basin production may vary based on numerous factors including overall crude oil prices and changes in costs of production.

Customers and Contracts. We ship crude oil as a common carrier for several different types of customers, including crude oil producers, end users such as refiners and marketing and trading companies, including our marketing affiliate. Published transportation tariffs filed with the FERC or the appropriate state agency serve as contracts to ship on our crude oil pipelines, and shippers nominate volumes to be transported up to a month in advance, with rates varying by origin, destination and product grade. We typically reserve at least 10% of the shipping capacity of our pipelines for spot shippers. Spot barrel movements on our pipelines generally ship at higher rates than those charged to committed shippers. Generally, we secure long-term commitments to support our long-haul crude oil pipeline assets. The majority of the capacity on our Longhorn pipeline is supported by take-or-pay commitments, with a portion of those commitments set to expire in late 2020. We recently entered into a new long-term agreement for a significant portion of this capacity, with volumes under this new agreement ramping up over the next few years. Our Houston distribution system is generally not subject to long-term agreements. For 2019, approximately 30% of all volumes on our wholly-owned crude oil pipelines were subject to long-term commitments. The average remaining life of these contracts was approximately four years as of December 31, 2019. As of December 31, 2019, approximately 90% of our crude oil storage available for contract was under agreements with terms in excess of one year or that renew on an annual basis at our customers' option. The average remaining life of our storage contracts was approximately two years as of December 31, 2019. These agreements obligate the customer to pay for storage capacity reserved even if not used by the customer. BridgeTex, Double Eagle, Saddlehorn and Seabrook also have long-term contracts. Additionally, we have a tolling agreement with one customer for the exclusive use of our condensate splitter in Corpus Christi with a remaining life of approximately three years.

GENERAL BUSINESS INFORMATION

Major Customers

No customer accounted for more than 10% of our consolidated revenues during 2017, 2018 or 2019.

Commodity Positions and Hedges

Our policy is generally to purchase only those products necessary to conduct our normal business activities. We do not acquire physical inventory, futures contracts or other derivative instruments for the purpose of speculating on commodity price changes. Our gas liquids blending, fractionation and crude oil marketing activities result in our carrying significant levels of petroleum product inventories. In addition, we hold positions related to tender deductions and product overages. We use forward physical contracts and derivative instruments to hedge against commodity price changes and manage risks associated with our various commodity purchase and sale activities. Our risk management policies and procedures are designed to monitor our derivative instrument positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity to help ensure that our hedging activities address the risks inherent in our commodity positions.

Regulation

Tariff Regulation. Our interstate common carrier pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act, the Energy Policy Act of 1992 and rules and orders promulgated pursuant thereto. FERC regulation requires that interstate liquids pipeline rates be filed with the FERC, be posted publicly, be nondiscriminatory, and be "just and reasonable." Rate changes and the overall level of our rates may be subject to challenge by the FERC or shippers. If the FERC determines that our rates are not just and reasonable, we may be required to reduce our rates and pay refunds for up to two years of over-earning. The rates on approximately 40% of the shipments on our refined products pipeline system are regulated by the FERC primarily through an index methodology, which for the five-year period beginning July 1, 2016 is set at the annual change in the producer price index for finished goods ("PPI-FG") plus 1.23%. As an alternative to cost-of-service or index-based rates, interstate liquids pipeline companies may establish rates by obtaining authority to charge market-based rates in competitive markets or by negotiation with unaffiliated shippers. Approximately 60% of our refined products pipeline system's markets are either subject to regulations by the states in which we operate or are approved for market-based rates by the FERC, and in both cases these rates can generally be adjusted at our discretion based on market factors. Most of the tariffs on our long-haul crude oil pipelines are established by negotiated rates that generally provide for annual adjustments in line with changes in the FERC index, subject to certain modifications.

In addition, some shipments on our pipeline systems move within a single state and thus are considered to be intrastate commerce. The rates, terms and conditions of service offered by our intrastate pipelines are subject to certain regulations with respect to such intrastate transportation by state regulatory authorities in the states of Colorado, Illinois, Kansas, Minnesota, Oklahoma, Texas and Wyoming. Such state regulatory authorities could limit our ability to increase our rates or to set rates based on our costs, or could order us to reduce our rates and require the payment of refunds to shippers if our rates are found to have been unjust.

Commodity Market Regulation. Our conduct in petroleum markets and in hedging our exposure to commodity price fluctuations must comply with laws and regulations that prohibit market manipulation.

Wholesale sales of petroleum products are subject to provisions of the Energy Independence and Security Act of 2007 (“EISA”) and regulations by the Federal Trade Commission (“FTC”). Under the EISA, the FTC issued a rule that prohibits fraudulent or deceptive conduct (including false or misleading statements of material fact) in connection with wholesale purchases or sales of crude oil or refined products. The FTC rule also bans intentional failures to state a material fact when the omission makes a statement misleading and distorts, or is likely to distort, market conditions for any product covered by the rule. The FTC holds substantial enforcement authority under the EISA, including authority to request that a court impose significant fines.

Under the Commodity Exchange Act, the Commodity Futures Trading Commission (“CFTC”) is directed to prevent price manipulations for the commodities markets, including the physical energy, futures and swaps markets. Pursuant to the Dodd-Frank Act, the CFTC has adopted additional anti-market manipulation regulations that prohibit, among other things, fraud and price manipulation in the physical energy, futures and swaps markets. The CFTC also has statutory authority to assess significant fines.

Renewable Fuel Standard. We are an obligated party under the Renewable Fuel Standard (“RFS”) promulgated by the Environmental Protection Agency (“EPA”) and are required to satisfy our Renewable Volume Obligation (“RVO”) on an annual basis. To meet the RVO, the gasoline products we produce in our gas liquids blending activities must either contain the mandated renewable fuel components, or credits must be purchased to cover any shortfall. We met our RVO requirements for 2019 and expect to satisfy the requirements for 2020 mainly through the purchase of credits, known as Renewable Identification Numbers (“RINs”). As the RFS program is currently structured, the RVO of all obligated parties will increase over time unless adjusted by the EPA. The ability to incorporate increasing volumes of renewable fuel components into fuel products and the availability of RINs may be limited, which could increase our costs to comply with the RFS standards or limit our ability to blend.

Income Taxes. We are a partnership for income tax purposes and, therefore, are not subject to federal or state income taxes for most of the states in which we operate. The tax on our net income is borne by our unitholders through allocation to them of their share of our taxable income. Net income for financial statement purposes may differ significantly from taxable income allocated to unitholders because of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder’s tax attributes is not available to us.

As a publicly traded limited partnership, we are subject to a statutory requirement that our “qualifying income” (as defined by the Internal Revenue Code, related Treasury Regulations and Internal Revenue Service pronouncements) exceed 90% of our total gross income, determined on a calendar year basis. If our qualifying income does not meet this statutory requirement, we could be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2017, 2018 and 2019, our qualifying income met the statutory requirement.

Environmental, Maintenance, Safety & Security

General. The operation of our pipeline systems, terminals and associated facilities is subject to strict and complex laws and regulations relating to the protection of the environment and workplace safety. These laws and regulations govern many aspects of our business including the work environment, the generation and disposal of waste, discharge of process and storm water, air emissions, remediation requirements and facility design requirements to protect against releases into the environment. We believe our assets are designed, operated and maintained in material compliance with these laws and regulations.

Environmental. Our estimates for remediation liabilities assume that we will be able to use traditionally acceptable remediation and monitoring methods, as well as associated engineering or institutional controls, to comply with applicable regulatory requirements. These estimates include the cost of performing environmental assessments, remediation and monitoring of the impacted environment such as soils, groundwater and surface water conditions. Our recorded environmental liabilities are estimates and total remediation costs may differ from current estimated amounts.

We may experience future releases of regulated materials into the environment or discover historical releases that were previously unidentified. While an asset integrity and maintenance program designed to prevent, promptly detect and address releases is an integral part of our operations, damages and liabilities arising out of any environmental release from our assets identified in the future could have a material adverse effect on our results of operations, financial position or cash flow.

Liabilities recognized for estimated environmental costs were $20.5 million and $14.9 million at December 31, 2018 and 2019, respectively. Environmental liabilities have been classified as other current or noncurrent based on management's estimates regarding the timing of actual payments. We have insurance policies that provide coverage for remediation costs and liabilities arising from sudden and accidental releases of products applicable to all of our assets. Receivables from insurance carriers related to environmental matters were $4.1 million and $2.9 million at December 31, 2018 and 2019, respectively.

Hazardous Substances and Wastes. Our operations are subject to various laws and regulations that relate to the release of hazardous substances and solid wastes into water or soils. For instance, the Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment.

Our operations generate wastes, including hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. We are not currently required to comply with a substantial portion of the RCRA requirements as our operations routinely generate only small quantities of hazardous wastes, and we are not a hazardous waste treatment, storage or disposal facility operator that is required to obtain a RCRA hazardous waste permit. While RCRA currently exempts a number of wastes from being subject to hazardous waste requirements, including many oil and gas exploration and production wastes, the EPA could consider the adoption of stricter disposal standards for non-hazardous wastes. Moreover, it is possible that additional wastes, which could include non-hazardous wastes currently generated during operations, may be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly storage and disposal requirements than non-hazardous wastes. Changes in the regulations could materially increase our expenses.

We own or lease properties where hydrocarbons have been handled for many years. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on, under or from the properties owned or leased by us or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties were previously operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws.

Under these laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed of or released by prior owners or operators, to remediate contaminated property, including groundwater contaminated by prior owners or operators, or to make capital improvements to prevent future contamination.

Water Discharges. Our operations can result in the discharge of pollutants, including crude oil and refined products, and are subject to the Oil Pollution Act ("OPA") and Clean Water Act ("CWA"). The OPA and CWA subject owners of facilities to strict, joint and potentially significant liability for removal costs and certain other consequences of a product spill such as natural resource damages, where the product spills into regulated waters, along federal shorelines or in the exclusive economic zone of the U.S. In the event of a product spill from one of our facilities into regulated waters, substantial liabilities could be imposed. States in which we operate have also enacted similar laws. The CWA imposes restrictions and strict controls regarding the discharge of pollutants into regulated waters. This law and comparable state laws require that permits be obtained to discharge pollutants into regulated waters and impose substantial potential liability for non-compliance. Compliance with these laws is not expected to have a material adverse effect on our business, financial position, results of operations or cash flows.

Air Emissions. Our operations are subject to the federal Clean Air Act ("CAA") and comparable state and local laws and regulations, which regulate emissions of air pollutants from various industrial sources, including certain of our facilities, and impose various operating, monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or increase air emissions, obtain and strictly comply with air permits and regulations containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe that our operations will not be materially adversely affected by such requirements.

Greenhouse Gas Emissions. The EPA has adopted regulations under existing provisions of the CAA that require certain large stationary sources to obtain pre-construction permits and operating permits for greenhouse gas emissions. In addition, the EPA requires the monitoring and reporting of greenhouse gas emissions from certain large greenhouse gas emissions sources, including petroleum facilities.

Federal and state legislative and regulatory initiatives may attempt to further address climate change or control or limit greenhouse gas emissions. Although it is not possible at this time to predict how they would impact our business, any such future laws or regulations could adversely affect demand for the products that we transport, store and distribute. Depending on the particular programs adopted, they could also increase our costs to operate and maintain our facilities by requiring that we measure and report our emissions, install new emission controls on our facilities, acquire allowances to authorize our emissions, pay any taxes related to our emissions and administer and manage an emissions program, among other things. We may be unable to include some or all of such increased costs in the rates charged to our customers and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before the FERC or state regulatory agencies and the provisions of any final legislation or implementing regulations.

Finally, many scientific studies conclude that increasing concentrations of greenhouse gases in the Earth's atmosphere affect climate changes, which could result in the increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, there may be an increased potential for adverse effects on our assets and operations.

Maintenance. Our pipeline systems are subject to regulation by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") under the Hazardous Liquid Pipeline Safety Act of 1979, as amended ("HLPSA"). The HLPSA prescribes and enforces minimum federal safety standards for the transportation of hazardous liquids by pipeline including the design, construction, testing, operation and maintenance, spill response planning, and overall reporting and management related to our pipeline facilities. In addition to the amended HLPSA covered in Title 49 of the *Code of Federal Regulations*, subsequent statutes provide the framework for the pipeline hazardous liquid safety program and include provisions related to PHMSA's authorities, administration, and regulatory activities. Most recently these statutes include the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and the Protecting our Infrastructure of Pipelines Enhancing Safety Act of 2016.

On October 1, 2019 PHMSA published in the Federal Register amendments to the Pipeline Safety Regulations codified at Title 49 of the *Code of Federal Regulations*. The revised rule includes, among other items, the requirement for integrity assessments at least once every 10 years for pipeline segments located outside of high consequence areas ("HCAs") and requires all pipelines in HCAs to be capable of accommodating in-line inspection tools within 20 years unless basic construction cannot accommodate in-line inspection tools. The revised rule modified the definition of hazardous liquids to include ethanol, methanol, or other non-petroleum fuel which is flammable, toxic, or harmful to the environment and requires Geographic Information System ("GIS") spatial data integration and analysis within the Integrity Management Program that includes defined data integration attributes which must be incorporated by October 1, 2022. Unless noted otherwise in the Federal Register notice, all requirements of the rule will take effect on July 1, 2020. We believe the revised rule will not have a material impact on our business.

PHMSA is advancing additional rulemakings regarding rupture detection, the installation of remotely controlled valves on newly constructed or entirely replaced hazardous liquid pipelines and revisions to the required repair criteria for integrity assessments. We believe that compliance with such regulatory changes will not have a material adverse effect on our results of operations.

In addition to regulations applicable to all of our pipelines, we have undertaken additional obligations to mitigate potential risks to health, safety and the environment on our Longhorn pipeline. Our compliance with these incremental obligations is subject to the oversight of the U.S. Department of Transportation through PHMSA.

States are largely preempted by federal law from regulating pipeline safety for interstate lines, but most states are certified by the U.S. Department of Transportation to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. States may adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines; however, states vary considerably in their authority and capacity to address pipeline safety. State standards may include requirements for facility design and management in addition to requirements for pipelines.

Our marine terminals along coastal waterways are subject to U.S. Coast Guard regulations and comparable state and municipal statutes relating to the design, installation, construction, testing, operation, replacement and management of these assets.

Safety. Our assets are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes, which, among other things, require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to employees, contractors, state and local governmental authorities and local citizens upon request. We are subject to OSHA process safety management regulations and EPA risk management plan rules that are designed to identify and establish procedures to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. Compliance with these laws is not expected to have a material adverse effect on our business, financial position, results of operations or cash flows.

Security. Our assets can be subject to both physical and cyber security regulations depending on the nature of the facility. Some of our assets are regulated by the Department of Transportation, the EPA, the United States Coast Guard and the Department of Homeland Security ("DHS"). Compliance with these regulations is achieved by creating physical security plans, minimal physical security standards, marine terminal security drills and annual security audits of both marine and DHS-regulated facilities. Compliance with these laws is not expected to have a material adverse effect on our business, financial position, results of operations or cash flows.

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property, and in some instances, these rights-of-way have limited terms that may require periodic renegotiation or, if such negotiations are unsuccessful, may require us to seek to exercise the power of eminent domain where such remedy is available. Several rights-of-way for our pipelines and other real property assets are shared with other pipelines and by third parties. In many instances, lands over which rights-of-way have been obtained are subject to prior liens, which have not been subordinated to the rights-of-way grants. We have obtained permits from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets and state highways, and in some instances, these permits are revocable at the election of the grantor. We have also obtained permits from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor's election. In some cases, property for pipeline purposes was purchased in fee. In some states and under some circumstances, we have the right of eminent domain to acquire rights-of-way and land necessary for our pipelines.

Some of the leases, easements, rights-of-way, permits and licenses that have been transferred to us are only transferable with the consent of the grantor of these rights, which in some instances is a governmental entity. We believe that we have obtained or will obtain sufficient third-party consents, permits and authorizations to operate our business in all material respects.

We believe that we have satisfactory title to all of our assets. Although title to our properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, liens that can be imposed in some jurisdictions for government-initiated action to clean up environmental contamination, liens for current taxes and other burdens, and easements, restrictions and other encumbrances to which the underlying properties were subject at the time of acquisition, we believe that none of these burdens should materially detract from the value of our properties or from our interest in them or should materially interfere with their use in the operation of our business.

Employees

As of December 31, 2019, we had 1,884 employees, 1,088 of which were assigned to our refined products segment and concentrated in the central U.S. Approximately 21% of our refined products segment employees were represented by the United Steel Workers and covered by a collective bargaining agreement that expires in January 2022. Approximately 3% of our refined products segment employees were represented by the International Union of Operating Engineers ("IUOE") and covered by a collective bargaining agreement that expires in October 2020. All of the IUOE employees are located at the New Haven terminal, which we sold in first quarter of 2020. There were 224 employees assigned to our crude oil segment and concentrated in the central U.S., and none of these employees were covered by a collective bargaining agreement.

(d) [Reserved.]

(e) Available Information

Our internet address is www.magellanlp.com. We make available free of charge on or through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

PART II

Item 6. *Selected Financial Data*

We have derived the summary selected historical financial data from our current and historical accounting records. Information concerning significant trends in our financial condition and results of operations is contained in Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Our operating results incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein not to be indicative of our future financial condition or results of operations. A discussion of our critical accounting estimates and how these estimates could impact our future financial condition or results of operations is included in *Management's Discussion and Analysis of Financial Condition and Results of Operations* under Item 7 of this report. In addition, a discussion of the risk factors that could affect our business and future financial condition or results of operations is included under Item 1A. *Risk Factors* in our Annual Report on Form 10-K for the year ended December 31, 2019. Additionally, the notes to our financial statements under Item 8. *Financial Statements and Supplementary Data* of this report include descriptions of areas where estimates and judgments could result in different amounts being recognized in our accompanying consolidated financial statements.

We believe that investors benefit from having access to the same financial measures utilized by management. In the following tables, we present the financial measure of distributable cash flow ("DCF"), which is not a generally accepted accounting principles ("GAAP") measure. Our partnership agreement requires that all of our available cash, less amounts reserved by our general partner's board of directors, be distributed to our unitholders. Management uses DCF to determine the amount of cash that our operations generated that is available for distribution to our unitholders and as a basis for recommending to our general partner's board of directors the amount of cash distributions to be paid each period. We also use DCF as the basis for calculating our equity-based long-term incentive compensation. A reconciliation of DCF to net income, the nearest comparable GAAP measure, is included in the following tables.

In addition to DCF, the non-GAAP measures of operating margin (in the aggregate and by segment) and Adjusted EBITDA are presented in the following tables. A reconciliation of operating margin to operating profit and net income to Adjusted EBITDA, which are the nearest comparable GAAP financial measures, are included in the following tables. See Note 3 – *Segment Disclosures* under Item *8. Financial Statements and Supplementary Data* of this report for a reconciliation of segment operating margin to segment operating profit. Operating margin is computed using amounts that are determined in accordance with GAAP and is an important measure of the economic performance of our core operations. Operating profit, alternatively, includes depreciation, amortization and impairment expense and general and administrative ("G&A") expense that management does not focus on when evaluating the core profitability of an operation. Adjusted EBITDA is an important measure utilized by management and the investment community to assess the financial results of a company.

Since the non-GAAP measures presented here include adjustments specific to us, they may not be comparable to similarly-titled measures of other companies.

	Year Ended December 31,				
	2015	2016	2017	2018	2019
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenue	$ 1,544,746	$ 1,591,119	$ 1,731,775	$ 1,878,988	$ 1,970,630
Product sales revenue	629,836	599,602	758,206	927,220	736,092
Affiliate management fee revenue	13,871	14,689	17,680	20,365	21,190
Total revenue	2,188,453	2,205,410	2,507,661	2,826,573	2,727,912
Operating expenses	523,650	528,672	577,978	649,436	634,081
Cost of product sales	447,273	493,338	635,617	704,313	619,279
Subtotal	1,217,530	1,183,400	1,294,066	1,472,824	1,474,552
Other operating income (expense)	—	—	—	—	2,975
Earnings of non-controlled entities	66,483	78,696	120,994	181,117	168,961
Operating margin	1,284,013	1,262,096	1,415,060	1,653,941	1,646,488
Depreciation, amortization and impairment expense	166,812	178,142	196,630	265,077	246,134
G&A expense	149,948	147,165	165,717	194,283	196,650
Operating profit	967,253	936,789	1,052,713	1,194,581	1,203,704
Interest expense, net	143,177	165,410	193,718	200,514	198,554
Gain on disposition of assets	—	(28,144)	(18,505)	(353,797)	(28,966)
Other (income) expense	2,618	(6,466)	4,139	13,868	11,830
Income before provision for income taxes	821,458	805,989	873,361	1,333,996	1,022,286
Provision for income taxes	2,336	3,218	3,830	71	1,437
Net income	$ 819,122	$ 802,771	$ 869,531	$ 1,333,925	$ 1,020,849
Basic net income per common unit	$ 3.60	$ 3.52	$ 3.81	$ 5.84	$ 4.46
Diluted net income per common unit	$ 3.59	$ 3.52	$ 3.81	$ 5.84	$ 4.46
Balance Sheets Data:					
Working capital (deficit)[a]	$ (374,218)	$ (111,262)	$ (239,899)	$ (30,213)	$ (207,468)
Total assets	$ 6,041,567	$ 6,772,073	$ 7,394,375	$ 7,747,537	$ 8,437,729
Long-term debt, net	$ 3,189,287	$ 4,087,192	$ 4,273,518	$ 4,211,380	$ 4,706,075
Partners' capital	$ 2,021,736	$ 2,092,105	$ 2,129,653	$ 2,643,434	$ 2,715,028
Cash Distribution Data:					
Cash distributions declared per unit[b]	$ 3.01	$ 3.32	$ 3.59	$ 3.87	$ 4.07
Cash distributions paid per unit[b]	$ 2.92	$ 3.25	$ 3.52	$ 3.79	$ 4.04

	Year Ended December 31,				
	2015	2016	2017	2018	2019
	(in thousands, except operating statistics)				
Other Data:					
Operating margin:					
Refined products	$ 891,213	$ 840,181	$ 934,984	$ 1,074,705	$ 1,025,497
Crude oil	388,949	416,960	474,802	573,289	615,485
Allocated partnership depreciation costs[(c)]	3,851	4,955	5,274	5,947	5,506
Operating margin	$ 1,284,013	$ 1,262,096	$ 1,415,060	$ 1,653,941	$ 1,646,488
Adjusted EBITDA and distributable cash flow:					
Net income	$ 819,122	$ 802,771	$ 869,531	$ 1,333,925	$ 1,020,849
Interest expense, net	143,177	165,410	193,718	200,514	198,554
Depreciation, amortization and impairment[(d)]	174,683	189,332	210,000	272,522	240,874
Equity-based incentive compensation[(e)]	6,461	4,982	6,766	22,768	14,247
Gain on disposition of assets[(f)]	—	(28,144)	(18,505)	(351,215)	(16,280)
Commodity-related adjustments[(g)]	13,988	64,257	12,463	(101,987)	88,223
Distributions received from operations of non-controlled entities in excess of earnings for the period	14,572	9,293	25,216	15,584	34,641
Other[(h)]	—	5,341	3,749	3,644	—
Adjusted EBITDA	1,172,003	1,213,242	1,302,938	1,395,755	1,581,108
Interest expense, net, excluding debt issuance cost amortization[(i)]	(140,464)	(162,251)	(190,403)	(197,274)	(186,942)
Maintenance capital[(j)]	(88,685)	(103,507)	(91,163)	(88,736)	(96,702)
Distributable cash flow	$ 942,854	$ 947,484	$ 1,021,372	$ 1,109,745	$ 1,297,464
Operating Statistics:					
Refined products:					
Transportation revenue per barrel shipped	$ 1.439	$ 1.473	$ 1.495	$ 1.556	$ 1.616
Volume shipped (million barrels):					
Gasoline	268.1	275.4	295.5	286.9	280.5
Distillates	152.5	150.2	166.2	181.7	184.6
Aviation fuel	21.2	25.7	26.5	31.0	41.1
Liquefied petroleum gases	9.7	10.4	9.9	11.0	9.7
Total volume shipped	451.5	461.7	498.1	510.6	515.9
Crude oil:					
Magellan 100%-owned assets:					
Transportation revenue per barrel shipped[(k)]	$ 1.118	$ 1.321	$ 1.348	$ 1.208	$ 0.939
Volume shipped (million barrels)[(k)]	209.9	187.0	196.4	242.8	317.2
Crude oil terminal average utilization (million barrels per month)	14.8	16.9	17.5	18.7	23.0
Select joint venture pipelines:					
BridgeTex - volume shipped (million barrels)[(l)]	75.2	79.0	98.4	138.2	156.3
Saddlehorn - volume shipped (million barrels)[(m)]	—	5.2	19.0	27.4	56.1

(a) Working capital deficit at December 31, 2015 and 2017 included the current portion of long-term debt of approximately $250 million for each period.

(b) Cash distributions declared were determined based on DCF generated for each calendar year. Distributions were declared and paid within 45 days following the close of each quarter. Cash distributions paid represent cash payments for distributions during each of the periods presented.

(c) Certain depreciation expense was allocated to our various business segments, which in turn recognized these allocated costs as operating expense, reducing segment operating margin by these amounts.

(d) Prior year amounts have been reclassified to conform with the current year’s presentation. Depreciation, amortization and impairment expense is excluded from DCF to the extent it represents a non-cash expense.

(e) Because we intend to satisfy vesting of unit awards under our equity-based long-term incentive compensation plan with the issuance of common units, expenses related to this plan generally are deemed non-cash and excluded for DCF purposes. The amounts above have been reduced by cash payments associated with the plan, which are primarily related to tax withholdings.

(f) Gains on disposition of assets are excluded from DCF to the extent they are not related to our ongoing operations. The 2019 amounts above are net of gains on the disposition of residual assets from expansion projects, which are considered ongoing in nature, and as such are included in DCF.

(g) See Item 7. *Management’s Discussion and Analysis of Financial Condition and Results of Operations – Distributable Cash Flow* for a description of items included in our commodity-related adjustments.

(h) Other adjustments in 2018 include a $3.6 million adjustment recorded to partners' capital as required by our adoption of Accounting Standards Update 2014-09, *Revenue from Contracts with Customers*. The amount represents cash that we had previously received for deficiency payments but did not yet recognize in net income under the previous revenue recognition standard. Other adjustments in 2016 and 2017 include payments received from HollyFrontier Corporation in conjunction with the February 2016 Osage Pipe Line Company, LLC ("Osage") exchange transaction. These payments replaced distributions we would have received had the Osage transaction not occurred and are, therefore, included in our calculation of DCF.

(i) Interest expense in 2019 includes $8.3 million of debt prepayment premiums, which are excluded from DCF as they are financing activities and are not related to our ongoing operations.

(j) Maintenance capital expenditure projects maintain our existing assets and do not generate incremental DCF (i.e. incremental returns to our unitholders). For this reason, we deduct maintenance capital expenditures to determine DCF.

(k) Volume shipped includes shipments related to our crude oil marketing activities. Revenues from those activities are reflected as product sales revenue in our consolidated financial statements. Transportation revenue per barrel shipped reflects average rates on third-party volume only.

(l) These volumes reflect the total shipments for the BridgeTex pipeline, which was owned 50% by us through September 28, 2018 and 30% thereafter.

(m) These volumes reflect the total shipments for the Saddlehorn pipeline, which is owned 40% by us and began operations in September 2016.

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

Introduction

During first quarter 2020, we completed a reorganization of our reportable segments. This reorganization was effected to reflect changes in the management of our business in conjunction with the sale of three of our marine terminals. Five of our marine terminals, including the terminals sold during first quarter 2020, were combined with our refined products segment and one terminal was combined with our crude oil segment based on the predominant types of product stored at the facilities. Accordingly, we have restated our segment disclosures for all previous periods included in this report.

We are a publicly traded limited partnership principally engaged in the transportation, storage and distribution of refined petroleum products and crude oil. As of December 31, 2019, our asset portfolio consisted of:

- our refined products segment, comprised of our approximately 9,800-mile refined products pipeline system with 53 terminals as well as 25 independent terminals not connected to our pipeline system and five marine terminals (one of which is owned through a joint venture); and

- our crude oil segment, comprised of approximately 2,200 miles of crude oil pipelines, a condensate splitter and 37 million barrels of aggregate storage capacity, of which approximately 25 million barrels are used for contract storage. Approximately 1,000 miles of these pipelines, the condensate splitter and 30 million barrels of this storage capacity (including 22 million barrels used for contract storage) are wholly-owned, with the remainder owned through joint ventures.

The following discussion and analysis should be read in conjunction with our revised consolidated financial statements and related notes included in this Exhibit 99.1 on Form 8-K for the year ended December 31, 2019.

See *Item 1. Business* for a detailed description of our business.

Overview

Our nation's energy infrastructure is essential to provide safe, cost-efficient, reliable services that benefit our everyday lives. Our assets are an integral part of this energy network, transporting and storing petroleum products that enable our neighbors to travel by airplane and vehicle, farmers to work their fields to feed the world, and industries to move important goods across the country.

During 2019, we spent nearly $1 billion on organic growth projects, the highest amount in our history. A number of significant projects supported by long-term commitments were completed and placed into service during the year, enabling us to enhance our service offerings in support of our customers' and the broader economy's needs.

With the growth of our nation's crude oil production, additional export capabilities have become of increased importance within our industry to distribute crude oil and refined petroleum products, such as gasoline and diesel fuel, to other markets within the United States and throughout the world.

To assist with this infrastructure need, we recently improved our refined products export capabilities by adding a new dock to our Galena Park, Texas marine terminal to provide our customers added flexibility at this critical and busy facility. Also in the Houston Ship Channel, we began operations at our new Pasadena joint venture marine terminal, with five million barrels of storage and two docks now complete and ready to serve our customers.

On the crude oil side, we expanded our export capabilities with more tankage constructed at our Seabrook Logistics joint venture terminal. Through our integrated service offering, customers can seamlessly transport crude oil from the prolific Permian Basin in west Texas through our pipeline systems to reach all of the refineries in the Houston and Texas City area or the export market through Seabrook Logistics.

We also significantly expanded our refined products capabilities in the state of Texas during 2019. Our refined products pipeline from Houston to west Texas has been constrained for quite some time, and our recently completed East Houston-to-Hearne pipeline is the first step to increase our capacity to meet additional demand for gasoline and diesel fuel in the Dallas-Ft. Worth area and other markets served by our system. The next step of this strategy is the expansion of our west Texas pipeline system, which we expect to be operational during mid-2020. Both of these projects are supported by long-term customer commitments and expected to generate attractive returns.

Disciplined Foundation

We remain focused on capital discipline and managing our business for the long term. In March 2020, we sold three of our marine terminals as a result of our continuous evaluation of existing assets. We are always looking for ways to optimize our portfolio, and the divestiture of assets outside of our strategic footprint is an important element of our capital discipline.

Solid relationships with quality customers are also an important aspect of managing our business for the long term. We are known in the industry for our strategic assets, and our customer base is primarily comprised of investment-grade companies that rely heavily on our services. For large capital projects, we seek long-term customer commitments to provide ratable income and mitigate market risk. Our business fundamentals and financial position remain strong, bolstered by our commitment to capital discipline that we believe will serve as the foundation of our long-term success.

Creating Long-Term Value

Managing our business in a prudent manner for the long-term benefit of our investors remains our top priority. While our business has continued to perform very well and demand for our services remains strong, increasingly competitive dynamics in the crude oil business warrant a more conservative approach to our long track record of distribution growth. As a result, we expect to increase our average cash distributions by 3% in 2020. We also intend to maintain distribution coverage above 1.2 times for the foreseeable future. We believe these actions are more in-line with the inherent long-term growth profile of our base business.

While we continue to evaluate well in excess of $500 million of potential organic growth projects that would create incremental value for our investors, the reality is that we will most likely be in a lower capital spending environment over the next few years. Our first priority continues to be investing in attractive, high-quality growth projects, but we remain committed to our long-standing approach to capital discipline. We only plan to move forward on new opportunities if they meet or exceed our targeted returns and are appropriately adjusted for risk and long-term sustainability of cash flows. To the extent we have fewer opportunities that meet these requirements, we believe excess cash flow can be efficiently returned to our investors via other tools, including unit repurchases or special distributions.

Looking toward 2020 and beyond, our financial position is strong, with one of the healthiest balance sheets in the midstream space. We are well-positioned to respond to a more challenging market environment for us and the industry in general over the next few years, and are determined to maintain a balanced approach to running our business efficiently while at the same time continuing to pursue value-added growth opportunities.

Recent Developments

Terminals Sale. In January 2020, we announced an agreement to sell three marine terminals to Buckeye Partners, L.P. for $250 million, which is expected to close as soon as first quarter 2020, subject to regulatory approvals. The terminals are located in New Haven, Connecticut, Wilmington, Delaware and Marrero, Louisiana and are included in our refined products segment.

Saddlehorn Pipeline Transactions. In August 2019, Saddlehorn announced the expansion of its pipeline capacity by a total of 100,000 barrels per day ("bpd") to a new total capacity of approximately 290,000 bpd. The higher capacity is expected to be available in late 2020 following the addition of incremental pumping and storage capabilities. In conjunction with increased volume commitments, an affiliate of Black Diamond Gathering LLC ("Black Diamond"), which is majority-owned by Noble Midstream Partners LP, obtained an option to buy up to a 20% ownership interest in Saddlehorn. In February 2020, Black Diamond exercised its option, and as a result, we and one of our joint venture co-owners, an affiliate of Plains All American Pipeline, L.P., each sold a 10% interest in Saddlehorn to Black Diamond. We do not expect significant changes to our equity earnings from these transactions.

Unit Repurchase Program. Also in January 2020, we announced that our general partner's board of directors authorized the repurchase of up to $750 million of our common units through 2022. We intend to purchase our common units from time-to-time through a variety of methods, including open market purchases and negotiated transactions, all in compliance with the rules of the Securities and Exchange Commission and other applicable legal requirements. The repurchase program does not obligate us to acquire any particular amount of common units, and the repurchase program may be suspended or discontinued at any time.

Cash Distribution. In January 2020, the board of directors of our general partner declared a quarterly cash distribution of $1.0275 per unit for the period of October 1, 2019 through December 31, 2019. This quarterly cash distribution was paid on February 14, 2020 to unitholders of record on February 7, 2020.

Results of Operations

We believe that investors benefit from having access to the same financial measures utilized by management. Operating margin, which is presented in the following table, is an important measure used by management to evaluate the economic performance of our core operations. Operating margin is not a generally accepted accounting principles ("GAAP") measure, but the components of operating margin are computed using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the following table. Operating profit includes expense items, such as depreciation, amortization and impairment expense and general and administrative ("G&A") expense, which management does not focus on when evaluating the core profitability of our separate operating segments. Additionally, product margin, which management primarily uses to evaluate the profitability of our commodity-related activities, is provided in this table. Product margin is a non-GAAP measure; however, its components of product sales revenue and cost of product sales are determined in accordance with GAAP. Our gas liquids blending, fractionation, crude oil marketing and other commodity-related activities generate significant revenue. We believe the product margin from these activities, which takes into account the related cost of product sales, better represents its importance to our results of operations.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2019

Financial Highlights ($ in millions, except operating statistics)	**Year Ended December 31,**		**Variance Favorable (Unfavorable)**	
	2018	**2019**	**$ Change**	**% Change**
Transportation and terminals revenue:				
Refined products	$ 1,316.6	$ 1,355.6	$ 39.0	3 %
Crude oil	566.1	620.4	54.3	10 %
Intersegment eliminations	(3.7)	(5.4)	(1.7)	(46)%
Total transportation and terminals revenue	1,879.0	1,970.6	91.6	5 %
Affiliate management fee revenue	20.4	21.2	0.8	4 %
Operating expenses:				
Refined products	486.5	471.7	14.8	3 %
Crude oil	172.5	173.3	(0.8)	— %
Intersegment eliminations	(9.6)	(10.9)	1.3	14 %
Total operating expenses	649.4	634.1	15.3	2 %
Product margin:				
Product sales revenue	927.2	736.1	(191.1)	(21)%
Cost of product sales	704.3	619.3	85.0	12 %
Product margin	222.9	116.8	(106.1)	(48)%
Other operating income (expense)	—	3.0	3.0	n/a
Earnings of non-controlled entities	181.1	169.0	(12.1)	(7)%
Operating margin	1,654.0	1,646.5	(7.5)	— %
Depreciation, amortization and impairment expense	265.1	246.1	19.0	7 %
G&A expense	194.3	196.7	(2.4)	(1)%
Operating profit	1,194.6	1,203.7	9.1	1 %
Interest expense (net of interest income and interest capitalized)	200.5	198.6	1.9	1 %
Gain on disposition of assets	(353.8)	(29.0)	(324.8)	(92)%
Other (income) expense	13.9	11.8	2.1	15 %
Income before provision for income taxes	1,334.0	1,022.3	(311.7)	(23)%
Provision for income taxes	0.1	1.5	(1.4)	(1,400)%
Net income	$ 1,333.9	$ 1,020.8	$ (313.1)	(23)%
Operating Statistics				
Refined products:				
Transportation revenue per barrel shipped	$ 1.556	$ 1.616		
Volume shipped (million barrels):				
Gasoline	286.9	280.5		
Distillates	181.7	184.6		
Aviation fuel	31.0	41.1		
Liquefied petroleum gases	11.0	9.7		
Total volume shipped	510.6	515.9		
Crude oil:				
Magellan 100%-owned assets:				
Transportation revenue per barrel shipped[(a)]	$ 1.208	$ 0.939		
Volume shipped (million barrels)[(a)]	242.8	317.2		
Crude oil terminal average utilization (million barrels per month)	18.7	23.0		
Select joint venture pipelines:				
BridgeTex - volume shipped (million barrels)[(b)]	138.2	156.3		
Saddlehorn - volume shipped (million barrels)[(c)]	27.4	56.1		

(a) Volume shipped includes shipments related to our crude oil marketing activities. Revenues from those activities are reflected as product sales revenue in our consolidated financial statements. Transportation revenue per barrel shipped reflects average rates on third-party volume only.
(b) These volumes reflect total shipments for the BridgeTex pipeline, owned 50% by us through September 28, 2018 and 30% thereafter.
(c) These volumes reflect the total shipments for the Saddlehorn pipeline, owned 40% by us.

Transportation and terminals revenue increased by $91.6 million, resulting from:

- an increase in refined products revenue of $39.0 million due to a higher average transportation rate per barrel. The average rate per barrel in the current year was favorably impacted by the 2018 and 2019 mid-year tariff adjustments. Volume increased slightly between periods as additional shipments associated with a recent connection near El Paso and our new East Houston-to-Hearne pipeline segment were mainly offset by less short-haul movements on the South Texas pipelines. These supply-driven barrels were also primarily responsible for fluctuations between periods in the product mix we transported. Terminal revenue also increased primarily due to additional fees from new dock capacity at our Galena Park facility and higher storage availability related to timing of maintenance work; and

- an increase in crude oil revenue of $54.3 million primarily due to higher revenues from system storage that we provide to our customers in conjunction with new tanks at Cushing and Corpus Christi and increased system storage utilization at East Houston as well as storage capacity we lease from the Seabrook export facility. Higher transportation revenues from increased volumes on the Houston distribution system were partially offset by lower transportation revenue on our Longhorn pipeline as a result of lower average rates following long-term contract renewals in late 2018. Overall, the average crude oil transportation rate per barrel decreased between periods due to significantly higher volumes on our Houston distribution system, which move at a lower rate, and the lower average Longhorn rates; and

Operating expenses decreased $15.3 million, resulting from:

- a decrease in refined products expenses of $14.8 million primarily due to lower asset integrity spending due to timing of maintenance work and lower compensation costs as a result of a pension valuation correction in 2018, partially offset by less favorable product overages (which reduce operating expenses) and higher property taxes;

- an increase in crude oil expenses of $0.8 million primarily due to fees we now pay to Seabrook for contract storage and ancillary services that we utilize to provide services to our shippers, largely offset by more favorable product overages (which reduce operating expenses), lower environmental accruals and lower expenses related to asset retirements; and

Product margin decreased $106.1 million primarily due to losses recognized in the current year on futures contracts compared to gains recognized in the prior year, partially offset by higher margins from our gas liquids blending activities. See Note 13 – *Derivative Financial Instruments* in Item 8. *Financial Statements and Supplementary Data*, as well as *Other Items—Commodity Derivative Agreements* below, for more information about our futures contracts.

Other operating income of $3.0 million in 2019 was primarily due to insurance settlements received in the current year related to Hurricane Harvey and proceeds received under a basis derivative agreement, largely offset by unrealized fair value adjustments on the basis derivative agreement.

Earnings of non-controlled entities decreased $12.1 million primarily due to lower earnings from Powder Springs as a result of losses recognized in the current year on futures contracts compared to gains in the prior year. Otherwise, lower BridgeTex earnings following the sale of a portion of our investment, representing a 20% interest, in late 2018 were mainly offset by higher earnings from Saddlehorn due to increased volumes and higher earnings from Seabrook due to the initiation of export capabilities in August 2018.

Depreciation, amortization and impairment expense decreased $19.0 million primarily due to a $49.1 million asset impairment charge recognized in 2018 related to our ammonia pipeline, partially offset by commencement of depreciation for expansion capital projects recently placed into service in the current year.

G&A expense increased $2.4 million primarily due to higher compensation costs resulting from higher bonus accruals due to company performance.

Interest expense, net of interest income and interest capitalized, decreased $1.9 million in 2019 primarily due to higher interest capitalized, partially offset by $8.3 million of debt prepayment costs in 2019 related to the early extinguishment of our 6.55% notes that were due July 2019. Our average outstanding debt increased from $4.5 billion in 2018 to $4.6 billion in 2019. Our weighted-average interest rate decreased from 4.8% in 2018 to 4.6% in 2019.

Gain on disposition of assets was $324.8 million unfavorable. In 2019, we recognized a deferred gain of $11.0 million related to the 2018 sale of our investment in BridgeTex, $12.7 million related to our discontinued Delaware Basin pipeline construction project that was sold to a third party and $5.3 million resulting from the sale of an inactive terminal along our refined products pipeline system. In 2018, we recognized a $353.8 million gain on the sale of a portion of our interest in BridgeTex.

Other expense was $2.1 million favorable in 2019 primarily due to lower pension-related costs in the current period. The 2018 period included the impact of a pension valuation correction.

Provision for income taxes was $1.4 million higher primarily due to favorable adjustments in 2018 resulting from the impact of a change in our tax position related to depreciation.

See Part I, Item 7. "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations*" in our 2018 Annual Report on Form 10-K for a comparative discussion of the years ended December 31, 2017 and 2018.

Distributable Cash Flow

Distributable cash flow ("DCF") and Adjusted EBITDA are non-GAAP measures. See Item 6. *Selected Financial Data* for a discussion of how management uses these non-GAAP measures. A reconciliation of DCF and Adjusted EBITDA for the years ended December 31, 2018 and 2019 to net income, which is the nearest comparable GAAP financial measure, is as follows (in millions):

	Year Ended December 31,	
	2018	**2019**
Net income	$ 1,333.9	$ 1,020.8
Interest expense, net	200.5	198.6
Depreciation, amortization and impairment[1]	272.5	240.9
Equity-based incentive compensation[2]	22.8	14.2
Gain on disposition of assets[3]	(351.2)	(16.3)
Commodity-related adjustments:		
Derivative (gains) losses recognized in the period associated with future transactions[4]	(71.5)	29.7
Derivative gains (losses) recognized in previous periods associated with transactions completed in the period[4]	(39.6)	71.2
Inventory valuation adjustments[5]	9.2	(12.7)
Total commodity-related adjustments	(101.9)	88.2
Distributions received from operations of non-controlled entities in excess of earnings	15.6	34.7
Other[6]	3.6	—
Adjusted EBITDA	1,395.8	1,581.1
Interest expense, net, excluding debt issuance cost amortization[7]	(197.3)	(186.9)
Maintenance capital[8]	(88.7)	(96.7)
DCF	$ 1,109.8	$ 1,297.5

(1) Prior year amounts have been reclassified to conform with the current year's presentation. Depreciation, amortization and impairment expense is excluded from DCF to the extent it represents a non-cash expense.

(2) Because we intend to satisfy vesting of unit awards under our equity-based long-term incentive compensation plan with the issuance of common units, expenses related to this plan generally are deemed non-cash and excluded for DCF purposes. The amounts above have been reduced by cash payments associated with the plan, which are primarily related to tax withholdings.

(3) Gains on disposition of assets are excluded from DCF to the extent they are not related to our ongoing operations. The 2019 amounts above are net of gains on the disposition of residual assets from expansion projects, which are considered ongoing in nature, and as such are included in DCF.

(4) Certain derivatives have not been designated as hedges for accounting purposes and the mark-to-market changes of these derivatives are recognized currently in net income. We exclude the net impact of these derivatives from our determination of DCF until the transactions are settled and, where applicable, the related products are sold. In the period in which these transactions are settled and any related products are sold, the net impact of the derivatives is included in DCF.

(5) We adjust DCF for lower of average cost or net realizable value adjustments related to inventory and firm purchase commitments as well as market valuations of short positions recognized each period as these are non-cash items. In subsequent periods when we physically sell or purchase the related products, we adjust DCF for the valuation adjustments previously recognized.

(6) Other adjustments in 2018 include a $3.6 million adjustment recorded to partners' capital as required by our adoption of Accounting Standards Update 2014-09, *Revenue from Contracts with Customers*. The amount represents cash that we had previously received for deficiency payments but did not yet recognize in net income under the previous revenue recognition standard.

(7) Interest expense in 2019 includes $8.3 million of debt prepayment premiums that are excluded from DCF as they are financing activities and are not related to our ongoing operations.

(8) Maintenance capital expenditures maintain our existing assets and do not generate incremental DCF (i.e. incremental returns to our unitholders). For this reason, we deduct maintenance capital expenditures to determine DCF.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Operating Activities. Net cash provided by operating activities was $1,353.0 million and $1,321.2 million for the years ended December 31, 2018 and 2019, respectively. The $31.8 million decrease from 2018 to 2019 was due to lower net income as previously described and changes in our working capital, partially offset by adjustments for non-cash items.

Investing Activities. Net cash used by investing activities for the years ended December 31, 2018 and 2019 was $119.3 million and $1,007.3 million, respectively. During 2019, we spent $980.6 million on capital expenditures, which included $96.7 million for maintenance capital, $791.8 million for our expansion capital projects and $92.1 million for undivided joint interest projects for which cash was received from a third party. Additionally, we made net capital contributions of $203.9 million to our joint ventures, which we account for as investments in non-controlled entities, of which $198.9 million related to capital projects. During 2018, we sold a portion of our interest in BridgeTex for cash proceeds of $575.6 million. Also during 2018, we spent $562.3 million on capital expenditures, which included $88.7 million for maintenance capital, $425.0 million for our expansion capital projects and $48.6 million for undivided joint interest projects for which cash was received from a third party. Additionally, we contributed capital of $216.4 million in conjunction with our joint venture capital projects, which we account for as investments in non-controlled entities.

Financing Activities. Net cash used by financing activities for the years ended December 31, 2018 and 2019 was $1,100.5 million and $538.6 million, respectively. During 2019, we paid cash distributions of $921.6 million to our unitholders. Additionally, we received net proceeds of $996.4 million from borrowings under long-term notes, which were used to repay our $550.0 million of 6.55% notes due 2019 and outstanding commercial paper borrowings at that time. Also, in January 2019, our equity-based incentive compensation awards that vested December 31, 2018 were settled by issuing 208,268 common units and distributing those units to the long-term incentive plan ("LTIP") participants, resulting in payments primarily associated with tax withholdings of $9.8 million. During 2018, we paid cash distributions of $865.4 million to our unitholders and repaid our $250.0 million of 6.40% notes due 2018. Also, in January 2018, our LTIP awards that vested December 31, 2017 were settled by issuing 168,913 common units to the LTIP participants, resulting in payments primarily associated with tax withholdings of $9.3 million.

The quarterly distribution amount related to fourth quarter 2019 earnings was $1.0275 per unit, which was paid in February 2020. Based on the number of common units currently outstanding and if we are able to meet management's targeted distribution growth of 3% during 2020, total cash distributions of approximately $953 million will be paid to our unitholders related to 2020 earnings. Management believes we will have sufficient DCF to fund these distributions.

See Part I, Item 7. "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources*" in our 2018 Annual Report on Form 10-K for a discussion of cash flows for the year ended December 31, 2017.

Capital Requirements

Capital spending for our business consists primarily of:

- Maintenance capital expenditures. These capital expenditures include costs required to maintain equipment reliability and safety and to address environmental and other regulatory requirements rather than to generate incremental DCF; and

- Expansion capital expenditures. These expenditures are undertaken primarily to generate incremental DCF and include costs to acquire or construct additional assets to grow our business and to expand or upgrade our existing facilities and to construct new assets, which we refer to collectively as organic growth projects. Organic growth projects include, for example, capital expenditures that increase storage or throughput volumes or develop pipeline connections to new supply sources.

During 2019, our maintenance capital spending was $96.7 million. For 2020, we expect to spend approximately $95 million on maintenance capital.

During 2019, we spent $990.7 million for our expansion capital projects, which included $198.9 million of contributions made to our joint ventures for their expansion projects. Based on the progress of projects already underway, we expect to spend approximately $400 million in 2020 to complete our current slate of expansion projects.

Liquidity

Cash generated from operations is a key source of liquidity for funding debt service, maintenance capital expenditures and quarterly distributions. Additional liquidity for purposes other than quarterly distributions, such as expansion capital expenditures and debt repayments, is available through borrowings under our commercial paper program and revolving credit facility, as well as from other borrowings or issuances of debt or common units (see Note 9 – *Debt* in *Item 8. Financial Statements and Supplementary Data* of this report for detail of our borrowings and debt outstanding at December 31, 2018 and 2019). If capital markets do not permit us to issue additional debt and equity securities, our business may be adversely affected, and we may not be able to acquire additional assets and businesses, fund organic growth projects or continue paying cash distributions at the current level.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2019 (in millions):

	Total	< 1 year	1-3 years	4-5 years	> 5 years
Long-term debt obligations[1]	$ 4,750.0	$ —	$ 550.0	$ —	$ 4,200.0
Interest obligations[1]	4,177.2	216.7	388.4	384.2	3,187.9
Operating lease obligations	195.3	32.3	60.1	52.3	50.6
Storage contract commitments[2]	19.3	7.4	10.2	0.6	1.1
Pipeline capacity commitments[3]	66.6	10.8	21.6	21.6	12.6
Right-of-way obligations[4]	13.3	1.8	3.5	3.3	4.7
Pension and postretirement medical obligations[5]	147.2	33.0	82.6	21.9	9.7
Purchase commitments:					
Product purchase commitments[6]	62.4	62.4	—	—	—
Utility purchase commitments	15.9	8.0	4.5	3.3	0.1
Derivative instruments[7]	—	—	—	—	—
Equity-based incentive awards[8]	52.1	31.0	21.1	—	—
Capital project purchase obligations	154.6	152.4	2.2	—	—
Maintenance obligations	113.8	113.2	0.6	—	—
Other	10.2	4.9	5.3	—	—
Total	$ 9,777.9	$ 673.9	$ 1,150.1	$ 487.2	$ 7,466.7

(1) At December 31, 2019, we had no borrowings outstanding under our revolving credit facility or commercial paper program. For purposes of this table, we have reflected no assumed borrowings under our revolving credit facility or commercial paper program for any periods presented. We have included interest obligations based on the stated amounts of our fixed-rate obligations.

(2) Includes product storage we have contracted from third parties. The cost of storage services is recognized in cost of product sales on our consolidated statements of income.

(3) Includes pipeline capacity we have contracted from third parties. The cost of these commitments is recognized in operating expense on our consolidated statements of income.

(4) Represents right-of-way agreements with a contractual maturity date over one year. The cost of these obligations is recognized in operating expense on our consolidated statements of income.

(5) Represents the projected benefit obligation of our pension and postretirement medical plans less the fair value of plan assets.

(6) Includes product purchase commitments for which the price provisions are indexed based on the date of delivery. We have estimated the value of these commitments using the related index price curve as of December 31, 2019. Also, we have excluded certain product purchase agreements for which there is no specified or minimum quantity.

(7) As of December 31, 2019, we had entered into exchange-traded futures contracts representing 3.2 million barrels of petroleum products that we expect to sell in the future and 0.7 million barrels of gas liquids we expect to purchase in the future. At December 31, 2019, we had recorded a net liability of $10.2 million and made margin deposits of $27.4 million. We have excluded from this table the future net cash outflows, if any, under these futures contracts and the amounts of future margin deposit requirements because those amounts are uncertain.

(8) Settlements of our LTIP awards will differ from these reported amounts primarily due to differences between actual and current estimates of payout percentages and completion of the remaining portion of the requisite service periods.

Other Items

Board of Director Election. In May 2019, Chansoo Joung was elected to our general partner's board of directors as an independent director.

Executive Officer Promotions and Retirements. Aaron Milford, who previously held the position of Chief Financial Officer and Senior Vice President, was elected by our general partner's board of directors as Chief Operating Officer effective May 1, 2019.

Jeff Holman, who previously held the position of Vice President, Finance and Treasurer, was elected by our general partner's board of directors as Chief Financial Officer, Senior Vice President and Treasurer, also effective May 1, 2019, filling the vacancy created by Mr. Milford's promotion.

Larry Davied, Senior Vice President of Technical Services, retired in September 2019 after 26 years of service with us or our predecessors. Michael Pearson was elected by our general partner's board of directors to succeed Mr. Davied in this position. Before his promotion, Mr. Pearson was Vice President, Asset Integrity and has been with us since our inception.

Crude Oil Revenues. The revenues generated by our crude oil assets partially depend upon the difference in commodity prices between different markets. When price differentials between origin and destination points on our crude oil pipelines are lower than our uncommitted (or spot) tariff rates, it is generally uneconomical for customers without contractual obligations to ship. We have benefited from favorable price differentials in recent periods, as the pricing differential between Midland and Houston has generally been above our spot rates, encouraging high utilization of our crude oil transportation and dock assets. However, in late 2019, the differential between Midland and Houston was lower than our tariff rates, primarily due to the addition of new crude oil pipeline capacity in the region. As a result, we expect lower volumes on our crude oil assets at our spot rates. In addition, customers will likely be less willing to make term commitments for our crude oil services, and the rates at which customers will be willing to pay for both term commitments and uncommitted capacity will decrease from the levels we experienced previously. Due to these reduced volumes and lower rates, we expect crude oil revenues from our wholly-owned and joint venture crude oil assets to decrease. To optimize utilization of our crude oil assets, we have developed new tariff arrangements that make our services more economical for our shippers. In addition, we have initiated crude oil marketing activities to facilitate intrastate shipments on our Texas assets.

Pipeline Tariff Changes. The Federal Energy Regulatory Commission ("FERC") regulates the rates charged on interstate common carrier pipeline operations primarily through an indexing methodology, which establishes the maximum amount by which index-based tariffs can be adjusted each year. Approximately 40% of our refined products tariffs are subject to this indexing methodology. The remaining 60% of our refined products tariffs are either subject to regulations by the states in which we operate or are approved for market-based rates by the FERC, and in both cases these rates can be adjusted at our discretion based on market factors. The current FERC-approved indexing method is the annual change in the producer price index for finished goods ("PPI-FG") plus 1.23%. Based on the preliminary estimates for this indexing methodology in 2019, we expect to increase rates in the 40% of our markets that are subject to the FERC's index methodology by approximately 2% on July 1, 2020. While we continue to evaluate the remaining 60% of our markets, we generally intend to increase rates in those markets by 3% to 4% on July 1, 2020, consistent with the 2019 rate increase for our competitive markets. Most of the tariffs on our long-haul crude oil pipelines are established at negotiated rates that generally provide for annual adjustments in line with changes in the FERC index, subject to certain modifications. We also expect to increase the rates of our crude oil pipelines by approximately 2% on average in July 2020.

Commodity Derivative Agreements. Certain of our business activities result in our owning various commodities, which exposes us to commodity price risk. We use forward physical commodity contracts and exchange-traded futures contracts to hedge against changes in prices of commodities that we expect to sell or purchase in future periods. During 2019, we also entered into a basis derivative agreement for which settlements are determined based on the basis differential of crude oil prices at different market locations.

For further information regarding the quantities of refined products and crude oil hedged at December 31, 2019 and the fair value of open hedge and basis derivative contracts at that date, please see Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* in our Annual Report on Form 10-K for the year ended December 31, 2019.

Related Party Transactions. See Note 17 – *Related Party Transactions* in Item 8. *Financial Statements and Supplementary Data* of this report for detail of our related party transactions.

Critical Accounting Estimates

Our management has discussed the development and selection of the following critical accounting estimates with the audit committee of our general partner's board of directors, which has reviewed and approved these disclosures.

Pension Obligations

We sponsor two union pension plans covering union employees and a pension plan for non-union employees. Various estimates and assumptions directly affect net periodic benefit expense and obligations for these plans. These estimates and assumptions include the expected long-term rates of return on plan assets, discount rates and the expected rate of compensation increase. Management reviews these assumptions annually and makes adjustments as necessary.

The following table presents the estimated increase (decrease) in net periodic benefit expense and obligations that would result from a 1% change in the specified assumption (in thousands):

	Benefit Expense		Benefit Obligation	
	1% Increase	1% Decrease	1% Increase	1% Decrease
Pension benefits:				
Discount rate	$ (5,313)	$ 6,552	$ (44,374)	$ 55,404
Expected long-term rate of return on plan assets	$ (2,572)	$ 2,572	$ —	$ —
Rate of compensation increase	$ 5,051	$ (5,047)	$ 27,444	$ (27,465)

The following table sets forth the increase (decrease) in our pension funding based on our current funding policy assuming a 1% change in the specified criterion (in thousands):

	1% Increase	1% Decrease
Rate of compensation increase	$ 600	$ (599)

The discount rate directly affects the measurement of the benefit obligations of our pension benefit plans. The objective of the discount rate is to determine the amount, if invested at the December 31 measurement date in a portfolio of high-quality fixed income securities, that would provide the necessary cash flows to make benefit payments when due. Decreases in the discount rate increase the obligation and generally increase the related expense, while increases in the discount rate have the opposite effect. Changes in general economic and market conditions that affect interest rates on long-term high-quality fixed income securities as well as the duration of our plans' liabilities affect our estimate of the discount rate.

We estimate the long-term expected rate of return on plan assets using expectations of capital market results, which includes an analysis of historical results as well as forward-looking projections. We base these capital market expectations on a long-term period and on our investment strategy and asset allocation. We develop our estimates using input from several external sources, including consultation with our third-party independent investment consultant. We develop the forward-looking capital market projections using a consensus of expectations by economists for inflation and dividend yield, along with expected changes in risk premiums. Because our determined rate is an estimate of future results, it could be significantly different from actual results. The expected rates of return on plan assets are long-term in nature; therefore, short-term market performance does not significantly affect our estimated long-term expected rate of return.

The expected rate of compensation increase represents average long-term salary increases. An increase in this rate causes the pension obligation and expense to increase.

Impairment of Long-Lived Assets, Goodwill and Investments

Impairment of Long-Lived Assets. Long-lived assets, including fixed assets and intangibles, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. Such indicators include, among others, the nature of the asset, the projected future economic benefit of the asset, changes in regulatory and political environments and historical and future cash flow and profitability measurements. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, we recognize an impairment charge for the excess of carrying value of the asset over its estimated fair value.

Goodwill. The goodwill relating to each of our reporting units is tested for impairment annually as well as when an event or change in circumstances indicates an impairment may have occurred. Under GAAP, we have the option to first assess qualitative factors to determine whether it is more likely than not that the fair value of one of our reporting units is greater than its carrying amount. If, after assessing the totality of events or circumstances, we determine it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, we are not required to perform any further testing. However, if we conclude otherwise, we perform the first step of a two-step impairment test by calculating the fair value of the reporting unit and comparing the fair value with the carrying amount of the reporting unit. If the fair value of the reporting unit is less than its carrying value, an impairment loss is recorded to the extent that the implied fair value of the goodwill of the reporting unit is less than its carrying value. We have the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to performing the first step of the two-step goodwill impairment test.

For purposes of performing the impairment test for goodwill, our reporting units are our reportable segments. In 2017 and 2018, we elected to complete the quantitative goodwill impairment test and began with step one of the test as required by GAAP. Based on these assessments, we calculated that the fair value of each of our reporting units was greater than its carrying amount. In 2019, we elected to perform the qualitative assessment described above for purposes of our annual goodwill impairment test. Based on this assessment, we concluded that it was more likely than not that the fair value of each of our reporting units was greater than its carrying amount. Accordingly, no further testing was required.

Determination as to whether and how much goodwill or long-lived assets are impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses and the outlook for national or regional market supply and demand conditions. We base the impairment reviews and calculations used in our impairment tests on assumptions that are consistent with our business plans and long-term investment decisions. See Note 5—*Property, Plant and Equipment, Goodwill and Other Intangibles* in Item 8. *Financial Statements and Supplementary Data* for additional information regarding impairments of goodwill and long-lived assets.

Investments. We evaluate investments in non-controlled entities for impairment whenever events or circumstances indicate that there is an other-than-temporary loss in value of the investment. When evidence of loss in value has occurred, we compare our estimate of fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. If the estimated fair value is less than the carrying value and we consider the decline in value to be other-than-temporary, the excess of the carrying value over the fair value is recognized in our consolidated financial statements as an impairment charge.

New Accounting Pronouncements

See Note 2 – *Summary of Significant Accounting Policies* in Item 8. *Financial Statements and Supplementary Data* of this report for a summary of new accounting pronouncements.

Item 8. *Financial Statements and Supplementary Data*

Management's Annual Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, as amended. Our 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.

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.

Management assessed the effectiveness of its internal control over financial reporting as of December 31, 2019. In making this assessment, it used the criteria set forth in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework*. As a result of this assessment management has concluded that, as of December 31, 2019, its internal control over financial reporting is effective based on those criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included in our Annual Report on Form 10-K, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2019. The report, which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2019, is included herein under the heading "Report of Independent Registered Public Accounting Firm" relative to internal control over financial reporting.

By: /s/ Michael N. Mears

Chairman of the Board, President, Chief Executive Officer and Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.

By: /s/ Jeff Holman

Senior Vice President, Chief Financial Officer and Treasurer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.

Report of Independent Registered Public Accounting Firm

To the Common Unitholders of Magellan Midstream Partners, L.P. and the Board of Directors of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Magellan Midstream Partners, L.P. (the Partnership) as of December 31, 2019 and 2018, the related consolidated statements of income, comprehensive income, partners' capital and cash flows for each of the three years in the period ended December 31, 2019, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership at December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated -February 18, 2020 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership'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 Partnership 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 Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the account or disclosures to which it relates.

Defined Benefit Pension Obligation

Description of the Matter

At December 31, 2019, the Partnership's defined benefit pension obligation was $381 million and exceeded the fair value of pension plan assets of $249 million, resulting in a net pension obligation of $132 million. As discussed in Note 11 to the consolidated financial statements, the Partnership updates the estimates used to measure the defined benefit pension obligation and plan assets annually or upon a remeasurement event to reflect the actual return on plan assets and updated actuarial assumptions.

Auditing the pension obligation was complex due to the judgmental nature of certain actuarial assumptions used in the measurement process, including the discount rate, mortality rates, retirement rate and future compensation levels. The projected benefit obligation was sensitive to these assumptions.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of controls over the Partnership's review of the defined benefit pension obligation calculations, the significant actuarial assumptions and the data inputs provided to the third-party actuary.

To test the defined benefit pension obligation, our audit procedures included, among others, evaluating the methodology used, the significant actuarial assumptions discussed above and the underlying data used in the measurement process. We compared the actuarial assumptions used by management to historical trends and evaluated the change in the defined benefit pension obligation from the prior year resulting from the change in service cost, interest cost, actuarial gains and losses, benefit payments, contributions and other activities. In addition, we involved our actuarial specialists to assist with our procedures including, among others, evaluating management's methodology for determining the discount rate that reflects the maturity and duration of the benefit payments and is used to measure the defined benefit pension obligation. As part of this assessment, we compared the projected cash flows used in the current year measurement of the pension obligation to those in the prior year and compared the current year benefits paid to the prior year projected payments. To evaluate the future mortality rates, retirement rate and future compensation levels, we assessed whether the information is consistent with publicly available information, and whether any market data adjusted for entity-specific adjustments were applied. We also tested the completeness and accuracy of the underlying data, including the participant data used in the actuarial calculations.

/s/ Ernst & Young LLP

We have served as the Partnership's auditor since 1999.
Tulsa, Oklahoma
February 18, 2020, except as it relates to the change in segments described under the Organization heading in Note 1 and the other matters disclosed in Note 16 and Note 19, as to which the date is May 4, 2020.

Report of Independent Registered Public Accounting Firm

To the Common Unitholders of Magellan Midstream Partners, L.P. and the Board of Directors of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.

Opinion on Internal Control Over Financial Reporting

We have audited Magellan Midstream Partners, L.P.'s internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Magellan Midstream Partners, L.P. (the Partnership) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Partnership as of December 31, 2019 and 2018, the related consolidated statements of income, comprehensive income, partners' capital and cash flows for each of the three years in the period ended December 31, 2019, and the related notes and our report dated February 18, 2020 expressed an unqualified opinion thereon.

Basis for Opinion

The Partnership'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. Our responsibility is to express an opinion on the Partnership'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 Partnership 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

An entity'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. An entity'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 entity; (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 entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity'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/ Ernst & Young LLP

Tulsa, Oklahoma
February 18, 2020

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit amounts)

	Year Ended December 31, 2017	2018	2019
Transportation and terminals revenue	$ 1,731,775	$ 1,878,988	$ 1,970,630
Product sales revenue	758,206	927,220	736,092
Affiliate management fee revenue	17,680	20,365	21,190
Total revenue	2,507,661	2,826,573	2,727,912
Costs and expenses:			
Operating	577,978	649,436	634,081
Cost of product sales	635,617	704,313	619,279
Depreciation, amortization and impairment	196,630	265,077	246,134
General and administrative	165,717	194,283	196,650
Total costs and expenses	1,575,942	1,813,109	1,696,144
Other operating income (expense)	—	—	2,975
Earnings of non-controlled entities	120,994	181,117	168,961
Operating profit	1,052,713	1,194,581	1,203,704
Interest expense	210,698	220,979	221,123
Interest capitalized	(15,565)	(17,455)	(19,284)
Interest income	(1,415)	(3,010)	(3,285)
Gain on disposition of assets	(18,505)	(353,797)	(28,966)
Other (income) expense	4,139	13,868	11,830
Income before provision for income taxes	873,361	1,333,996	1,022,286
Provision for income taxes	3,830	71	1,437
Net income	$ 869,531	$ 1,333,925	$ 1,020,849
Basic net income per common unit	$ 3.81	$ 5.84	$ 4.46
Diluted net income per common unit	$ 3.81	$ 5.84	$ 4.46
Weighted average number of common units outstanding used for basic net income per unit calculation	228,176	228,377	228,658
Weighted average number of common units outstanding used for diluted net income per unit calculation	228,338	228,573	228,842

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	Year Ended December 31,		
	2017	2018	2019
Net income	$ 869,531	$1,333,925	$1,020,849
Other comprehensive income (loss):			
Derivative activity:			
Net gain (loss) on cash flow hedges	(1,937)	4,317	(25,216)
Reclassification of net loss on cash flow hedges to income	2,958	2,958	2,736
Changes in employee benefit plan assets and benefit obligations recognized in other comprehensive income:			
Net actuarial loss	(46,008)	(2,323)	(27,351)
Amortization of prior service credit	(181)	(181)	(181)
Amortization of actuarial loss	6,371	10,352	5,820
Settlement cost	2,460	1,964	2,606
Total other comprehensive income (loss)	(36,337)	17,087	(41,586)
Comprehensive income	$ 833,194	$1,351,012	$ 979,263

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2018	December 31, 2019
ASSETS		
Current assets:		
Cash and cash equivalents	$ 218,283	$ 58,030
Trade accounts receivable	104,164	125,440
Other accounts receivable	25,007	23,887
Inventory	185,735	184,399
Commodity derivatives contracts, net	55,011	—
Commodity derivatives deposits	—	27,415
Other current assets	58,143	40,237
Total current assets	646,343	459,408
Property, plant and equipment	7,628,592	8,431,227
Less: accumulated depreciation	1,830,411	2,027,193
Net property, plant and equipment	5,798,181	6,404,034
Investments in non-controlled entities	1,076,306	1,240,551
Right-of-use asset, operating leases	—	171,868
Long-term receivables	20,844	20,782
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of $2,979 and $6,255 at December 31, 2018 and 2019, respectively)	51,174	47,898
Restricted cash	90,978	26,569
Other noncurrent assets	10,451	13,359
Total assets	$ 7,747,537	$ 8,437,729
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 138,735	$ 150,992
Accrued payroll and benefits	70,276	75,511
Accrued interest payable	63,258	64,276
Accrued taxes other than income	53,093	66,007
Deferred revenue	121,085	109,654
Accrued product liabilities	75,482	90,788
Commodity derivatives contracts, net	—	10,222
Commodity derivatives deposits	37,328	—
Current portion of operating lease liability	—	26,221
Current portion of long-term debt, net	59,489	—
Other current liabilities	57,810	73,205
Total current liabilities	676,556	666,876
Long-term operating lease liability	—	144,023
Long-term debt, net	4,211,380	4,706,075
Long-term pension and benefits	122,580	145,992
Other noncurrent liabilities	93,587	59,735
Commitments and contingencies		
Partners' capital:		
Common unitholders (228,195 units and 228,403 units outstanding at December 31, 2018 and 2019, respectively)	2,763,925	2,877,105
Accumulated other comprehensive loss	(120,491)	(162,077)
Total partners' capital	2,643,434	2,715,028
Total liabilities and partners' capital	$ 7,747,537	$ 8,437,729

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2017	2018	2019
Operating Activities:			
Net income	$ 869,531	$ 1,333,925	$1,020,849
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization and impairment expense	196,630	265,077	246,134
Gain on sale and retirement of assets	(5,135)	(328,055)	(28,966)
Earnings of non-controlled entities	(120,994)	(181,117)	(168,961)
Distributions from operations of non-controlled entities	146,211	196,686	203,602
Equity-based incentive compensation expense	20,641	32,053	24,012
Settlement cost, amortization of prior service credit and actuarial loss	8,650	12,135	8,245
Debt prepayment costs	—	—	8,270
Changes in components of operating assets and liabilities (Note 8)	15,695	22,246	7,994
Net cash provided by operating activities	1,131,229	1,352,950	1,321,179
Investing Activities:			
Additions to property, plant and equipment, net[1]	(558,669)	(552,257)	(943,990)
Proceeds from sale and disposition of assets	44,392	576,568	65,366
Investments in non-controlled entities	(134,828)	(216,424)	(212,380)
Distributions from returns of investments in non-controlled entities	55,931	1,786	8,494
Deposits received from undivided joint interest third party	—	71,071	75,258
Net cash used by investing activities	(593,174)	(119,256)	(1,007,252)
Financing Activities:			
Distributions paid	(803,216)	(865,431)	(921,606)
Net commercial paper repayments	(49,986)	—	—
Borrowings under long-term notes	496,705	—	996,405
Payments on notes	—	(250,000)	(550,000)
Debt placement costs	(6,316)	(404)	(12,012)
Net receipt (payment) on financial derivatives	—	24,619	(33,342)
Payments associated with settlement of equity-based incentive compensation	(13,875)	(9,285)	(9,764)
Debt prepayment costs	—	—	(8,270)
Net cash used by financing activities	(376,688)	(1,100,501)	(538,589)
Change in cash, cash equivalents and restricted cash	161,367	133,193	(224,662)
Cash, cash equivalents and restricted cash at beginning of period	14,701	176,068	309,261
Cash, cash equivalents and restricted cash at end of period	$ 176,068	$ 309,261	$ 84,599

Supplemental non-cash investing and financing activities:			
Contribution of property, plant and equipment to a non-controlled entity	$ 97,638	$ —	$ —
(1) Additions to property, plant and equipment	$ (572,744)	$ (562,296)	$ (980,575)
Changes in accounts payable and other current liabilities related to capital expenditures	14,075	10,039	36,585
Additions to property, plant and equipment, net	$ (558,669)	$ (552,257)	$ (943,990)

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
(In thousands)

	Common Unitholders	Accumulated Other Comprehensive Loss	Total Partners' Capital
Balance, January 1, 2017	$ 2,193,346	$(101,241)	$ 2,092,105
Comprehensive income:			
Net income	869,531	—	869,531
Total other comprehensive income (loss)	—	(36,337)	(36,337)
Total comprehensive income (loss)	869,531	(36,337)	833,194
Distributions	(803,216)	—	(803,216)
Equity-based incentive compensation expense	20,641	—	20,641
Issuance of common units in settlement of equity-based incentive plan awards	1,669	—	1,669
Payments associated with settlement of equity-based incentive compensation	(13,875)	—	(13,875)
Other	(865)	—	(865)
Balance, December 31, 2017	2,267,231	(137,578)	2,129,653
Comprehensive income:			
Net income	1,333,925	—	1,333,925
Total other comprehensive income (loss)	—	17,087	17,087
Total comprehensive income (loss)	1,333,925	17,087	1,351,012
Distributions	(865,431)	—	(865,431)
Equity-based incentive compensation expense	32,053	—	32,053
Issuance of common units in settlement of equity-based incentive plan awards	120	—	120
Payments associated with settlement of equity-based incentive compensation	(9,285)	—	(9,285)
ASC 606 cumulative effect	5,975	—	5,975
Other	(663)	—	(663)
Balance, December 31, 2018	2,763,925	(120,491)	2,643,434
Comprehensive income:			
Net income	1,020,849	—	1,020,849
Total other comprehensive income (loss)	—	(41,586)	(41,586)
Total comprehensive income (loss)	1,020,849	(41,586)	979,263
Distributions	(921,606)	—	(921,606)
Equity-based incentive compensation expense	24,012	—	24,012
Issuance of common units in settlement of equity-based incentive plan awards	480	—	480
Payments associated with settlement of equity-based incentive compensation	(9,764)	—	(9,764)
Other	(791)	—	(791)
Balance, December 31, 2019	$ 2,877,105	$(162,077)	$ 2,715,028

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Description of Business

Organization

Unless indicated otherwise, the terms "our," "we," "us" and similar language refer to Magellan Midstream Partners, L.P. together with its subsidiaries. Magellan Midstream Partners, L.P. is a Delaware limited partnership, and its common units are traded on the New York Stock Exchange under the ticker symbol "MMP." Magellan GP, LLC, a wholly owned Delaware limited liability company, serves as its general partner.

During first quarter 2020, we completed a reorganization of our reportable segments. This reorganization was effected to reflect changes in the management of our business in conjunction with the sale of three of our marine terminals. Five of our marine terminals, including the terminals sold during first quarter, were combined with our refined products segment and one terminal was combined with our crude oil segment based on the predominant types of product stored at the facilities. Accordingly, we have restated our segment disclosures for all previous periods included in this report.

Description of Business

We are principally engaged in the transportation, storage and distribution of refined petroleum products and crude oil. As of December 31, 2019, our asset portfolio consisted of:

- our refined products segment, comprised of our approximately 9,800-mile refined products pipeline system with 53 terminals as well as 25 independent terminals not connected to our pipeline system and five marine terminals (one of which is owned through a joint venture); and

- our crude oil segment, comprised of approximately 2,200 miles of crude oil pipelines, a condensate splitter and 37 million barrels of aggregate storage capacity, of which approximately 25 million barrels are used for contract storage. Approximately 1,000 miles of these pipelines, the condensate splitter and 30 million barrels of this storage capacity (including 22 million barrels used for contract storage) are wholly-owned, with the remainder owned through joint ventures; and

Description of Products

Terminology common in our industry includes the following terms, which describe products that we transport, store, distribute or otherwise handle through our petroleum pipelines and terminals:

- *refined products* are the output from crude oil refineries that are primarily used as fuels by consumers. Refined products include gasoline, diesel fuel, aviation fuel, kerosene and heating oil. Diesel fuel, kerosene and heating oil are also referred to as distillate;

- *transmix* is a mixture of refined products that forms when transported in pipelines. Transmix is fractionated and blended into usable refined products;

- *liquefied petroleum gases, or LPGs,* are liquids produced as by-products of the crude oil refining process and in connection with natural gas production. LPGs include butane and propane;

- *blendstocks* are products blended with refined products to change or enhance their characteristics such as increasing a gasoline's octane or oxygen content. Blendstocks include alkylates, oxygenates and natural gasoline;

- *heavy oils and feedstocks* are products used as burner fuels or feedstocks for further processing by refineries and petrochemical facilities. Heavy oils and feedstocks include No. 6 fuel oil and vacuum gas oil;

- *crude oil,* which includes condensate, is a naturally occurring unrefined petroleum product recovered from underground that is used as feedstock by refineries, splitters and petrochemical facilities; and
- *biofuels*, such as ethanol and biodiesel, are fuels derived from living materials and typically blended with other refined products as required by government mandates.

We use the term *petroleum products* to describe any, or a combination, of the above-noted products.

2. Summary of Significant Accounting Policies

Significant Accounting Policies

Basis of Presentation. Our consolidated financial statements include our refined products and crude oil operating segments. We consolidate all entities in which we have a controlling ownership interest. We apply the equity method of accounting to investments in entities over which we exercise significant influence but do not control. We eliminate all intercompany transactions.

Reclassifications. Certain prior year amounts have been reclassified to conform with the current period's presentation.

Use of Estimates. The preparation of our consolidated financial statements in conformity with U.S. generally accepted accounting principles ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of our consolidated financial statements, as well as their impact on the reported amounts of revenue and expense during the reporting periods. Actual results could differ from those estimates.

Cash Equivalents. Cash and cash equivalents include demand and time deposits and funds that own highly marketable securities with original maturities of three months or less when acquired. We periodically assess the financial condition of the institutions where we hold these funds, and, at December 31, 2018 and 2019, we believed our credit risk relative to these funds was minimal.

Restricted Cash. Restricted cash includes cash that we are contractually required to use for the construction of fixed assets and is unavailable for general use. It is classified as noncurrent due to its designation to be used for the construction of noncurrent assets.

Accounts Receivable and Allowance for Doubtful Accounts. Accounts receivable represent valid claims against customers. We recognize accounts receivable when we sell products or render services and collection of the receivable is probable. We extend credit terms to certain customers after a review of various credit indicators. We establish an allowance for doubtful accounts for all or any portion of an account where we consider collections to be at risk and evaluate reserves no less than quarterly to determine their adequacy. Judgments relative to at-risk accounts include the customers' current financial condition, the customers' historical relationship with us and current and projected economic conditions. We write off accounts receivable when we deem an account uncollectible.

Product Overages and Shortages. Each period end we measure the volume of each type of product in our pipeline systems and terminals, which is compared to the volumes of our customers' inventories (as adjusted for tender deductions). To the extent the product volumes in our pipeline systems and terminals exceed the volumes of our customers' book inventories, we recognize a gain from the product overage and increase our product inventories. To the extent the product in our pipeline systems and terminals is less than our customers' book inventories, we recognize a loss from the product shortage and we record a liability for product owed to our customers. The product overages we recognize are recorded based on market prices, and the resulting inventory is carried at weighted average cost. The product shortages we recognize are recorded based on our weighted average cost. Additionally, when product shortages result in a net short inventory position, the related liability is recorded based on period-end market prices. Product overages and shortages as well as adjustments to the value of net short inventory positions are recorded in operating expenses on our consolidated statements of income.

Income Taxes. We are a partnership for income tax purposes and therefore are not subject to federal or state income taxes for most of the states in which we operate. The tax on our net income is borne by our unitholders through allocation to them of their share of taxable income. Net income for financial statement purposes may differ significantly from taxable income of unitholders because of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder's tax attributes is not available to us.

The amounts recognized as provision for income taxes in our consolidated statements of income are primarily comprised of partnership-level taxes levied by the state of Texas. This tax is based on revenues less direct costs of sale for our assets apportioned to the state of Texas.

Net Income Per Unit. We calculate basic net income per common unit for each period by dividing net income by the weighted-average number of common units outstanding. The difference between our actual common units outstanding and our weighted-average number of common units outstanding used to calculate net income per common unit is due to the impact of: (i) the phantom units issued to our independent directors, which are included in the calculation of basic and diluted weighted average units outstanding and (ii) the weighted-average effect of units actually issued during a period. The difference between the weighted-average number of common units outstanding used for basic and diluted net income per unit calculations on our consolidated statements of income is primarily the dilutive effect of phantom unit awards granted pursuant to our long-term incentive plan, which have not yet vested in periods where contingent performance metrics have been met.

Index of Additional Significant Accounting Policies

Revenue from Contracts with Customers	*Note 4 – Revenue*
Property, Plant and Equipment	*Note 5 – Property, Plant and Equipment, Goodwill and Other Intangibles*
Goodwill and Other Intangible Assets	*Note 5 – Property, Plant and Equipment, Goodwill and Other Intangibles*
Investments in Non-Controlled Entities	*Note 6 – Investments in Non-Controlled Entities*
Inventory	*Note 7 – Inventory*
Leases	*Note 10 – Leases*
Pension and Postretirement Medical and Life Benefit Obligations	*Note 11 – Employee Benefit Plans*
Equity-Based Incentive Compensation	*Note 12 – Long-Term Incentive Plan*
Derivative Financial Instruments	*Note 13 – Derivative Financial Instruments*
Contingencies and Environmental	*Note 15 – Commitments and Contingencies*

New Accounting Pronouncements - Adopted by us on January 1, 2019

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-02, *Leases (Topic 842).* This ASU requires lessees to recognize a right-of-use asset and lease liability on the balance sheet for all leases, with the exception of short-term leases. The new accounting model for lessors remains largely the same, although some changes have been made to align it with the new lessee model and the new revenue recognition guidance. This update also requires companies to include additional disclosures regarding their lessee and lessor agreements. We adopted this standard on January 1, 2019, and it did not have a material impact on our consolidated statements of income or our leverage ratio as defined in our credit agreement. Adoption of this ASU resulted in an initial increase in our assets and liabilities by approximately $172 million due to the recognition of right-of-use assets and lease liabilities. See Note 10 – *Leases* for our lease disclosures.

3. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. Our segments are managed separately because each segment requires different marketing strategies and business knowledge. Management evaluates performance based on segment operating margin, which includes revenue from affiliates and external customers, operating expenses, cost of product sales and earnings of non-controlled entities.

We believe that investors benefit from having access to the same financial measures used by management. Operating margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. Operating margin is not a GAAP measure, but the components of operating margin are computed using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the tables below. Operating profit includes depreciation, amortization and impairment expense and G&A expense that management does not consider when evaluating the core profitability of our separate operating segments.

During 2018, we adopted ASC 606, *Revenue from Contracts with Customers.* Amounts from 2017 reflected in the following tables have not been adjusted and continue to be reflected in accordance with our historical accounting. Refer to Note 4 – *Revenue* for further details.

	Year Ended December 31, 2017 (in thousands)			
	Refined Products	Crude Oil	Intersegment Eliminations	Total
Transportation and terminals revenue	$ 1,261,012	$ 474,166	$ (3,403)	$ 1,731,775
Product sales revenue	723,153	35,053	—	758,206
Affiliate management fee revenue	3,730	13,950	—	17,680
Total revenue	1,987,895	523,169	(3,403)	2,507,661
Operating expenses	459,440	127,215	(8,677)	577,978
Cost of product sales	594,292	41,325	—	635,617
(Earnings) losses of non-controlled entities	(821)	(120,173)	—	(120,994)
Operating margin	934,984	474,802	5,274	1,415,060
Depreciation, amortization and impairment expense	139,840	51,516	5,274	196,630
G&A expenses	122,127	43,590	—	165,717
Operating profit	$ 673,017	$ 379,696	$ —	$ 1,052,713
Additions to long-lived assets	$ 391,955	$ 172,732		$ 564,687

	As of December 31, 2017			
Segment assets	$ 4,279,700	$ 2,908,535		$ 7,188,235
Corporate assets				206,140
Total assets				$ 7,394,375
Goodwill	$ 41,178	$ 12,082		$ 53,260
Investments in non-controlled entities	$ 121,479	$ 961,032		$ 1,082,511

	Year Ended December 31, 2018 (in thousands)			
	Refined Products	Crude Oil	Intersegment Eliminations	Total
Transportation and terminals revenue	$ 1,316,616	$ 566,063	$ (3,691)	$ 1,878,988
Product sales revenue	880,453	46,767	—	927,220
Affiliate management fee revenue	5,533	14,832	—	20,365
Total revenue	2,202,602	627,662	(3,691)	2,826,573
Operating expenses	486,596	172,478	(9,638)	649,436
Cost of product sales	660,185	44,128	—	704,313
Earnings of non-controlled entities	(18,884)	(162,233)	—	(181,117)
Operating margin	1,074,705	573,289	5,947	1,653,941
Depreciation, amortization and impairment expense	202,047	57,083	5,947	265,077
G&A expenses	140,333	53,950	—	194,283
Operating profit	$ 732,325	$ 462,256	$ —	$ 1,194,581
Additions to long-lived assets	$ 357,359	$ 148,995		$ 506,354
	As of December 31, 2018			
Segment assets	$ 4,687,351	$ 2,803,895		$ 7,491,246
Corporate assets				256,291
Total assets				$ 7,747,537
Goodwill	$ 41,178	$ 12,082		$ 53,260
Investments in non-controlled entities	$ 292,820	$ 783,486		$ 1,076,306

	Year Ended December 31, 2019 (in thousands)			
	Refined Products	Crude Oil	Intersegment Eliminations	Total
Transportation and terminals revenue	$ 1,355,682	$ 620,365	$ (5,417)	$ 1,970,630
Product sales revenue	707,812	28,280	—	736,092
Affiliate management fee revenue	6,719	14,471	—	21,190
Total revenue	2,070,213	663,116	(5,417)	2,727,912
Operating expenses	471,743	173,261	(10,923)	634,081
Cost of product sales	591,228	28,051	—	619,279
Other operating (income) expense	(10,185)	7,210	—	(2,975)
Earnings of non-controlled entities	(8,070)	(160,891)	—	(168,961)
Operating margin	1,025,497	615,485	5,506	1,646,488
Depreciation, amortization and impairment expense	174,096	66,532	5,506	246,134
G&A expenses	140,735	55,915	—	196,650
Operating profit	$ 710,666	$ 493,038	$ —	$ 1,203,704
Additions to long-lived assets	$ 805,902	$ 74,235		$ 880,137
	As of December 31, 2019			
Segment assets	$ 5,411,920	$ 2,894,733		$ 8,306,653
Corporate assets				131,076
Total assets				$ 8,437,729
Goodwill	$ 41,178	$ 12,082		$ 53,260
Investments in non-controlled entities	$ 422,384	$ 818,167		$ 1,240,551

4. Revenue

Revenue recognition policies

Revenue is recognized upon the satisfaction of each performance obligation required by our customer contracts. Transportation and terminals revenue is recognized over time as our customers receive the benefits of our service as it is performed on their behalf using an output method based on actual deliveries. Revenue for our storage services is recognized over time using an output method based on the capacity of storage under contract with our customers. Product sales revenue is recognized at a point in time when our customers take control of the commodities purchased. We record back-to-back purchases and sales of petroleum products on a net basis.

We recognize pipeline transportation revenue for crude oil shipments when our customers' product arrives at the customer-designated destination. For shipments of refined products under published tariffs that combine transportation and terminalling services, we recognize revenue when our customers take delivery of their product from our system. For shipments where terminalling services are not included in the tariff, we recognize revenue when our customers' product arrives at the customer-designated destination. We have certain contracts that require counterparties to ship a minimum volume over an agreed-upon time period, which are contracted as minimum dollar or volume commitments. Revenue pursuant to these take-or-pay contracts is recognized when the customers utilize their committed volumes. Additionally, when we estimate that the customers will not utilize all or a portion of their committed volumes, we recognize revenue in proportion to the pattern of exercised rights for the respective commitment period.

Our interstate common carrier petroleum products pipeline operations are subject to rate regulation by the Federal Energy Regulatory Commission ("FERC") under the Interstate Commerce Act, the Energy Policy Act of 1992 and rules and orders promulgated pursuant thereto. FERC regulation requires that interstate pipeline rates be filed with the FERC, be posted publicly and be nondiscriminatory and "just and reasonable." The rates on approximately 40% of the shipments on our refined products pipeline system are regulated by the FERC primarily through an index methodology. As an alternative to cost-of-service or index-based rates, interstate pipeline companies may establish rates by obtaining authority to charge market-based rates in competitive markets or by negotiation with unaffiliated shippers. Approximately 60% of our refined products pipeline system's markets are either subject to regulations by the states in which we operate or are approved for market-based rates by the FERC, and in both cases these rates can generally be adjusted at our discretion based on market factors. Most of the tariffs on our crude oil pipelines are established by negotiated rates that generally provide for annual adjustments in line with changes in the FERC index, subject to certain modifications.

For both our index-based rates and our market-based rates, our published tariffs serve as contracts, and shippers nominate the volume to be shipped up to a month in advance. These tariffs include provisions which allow us to deduct from our customer's inventory a small percentage of the products our customers transport on our pipeline systems. We refer to this non-monetary consideration as tender deduction revenue. We receive tender deductions from our customers as consideration for product losses during the transportation of petroleum products within our pipeline systems. Tender deduction revenue is generally recognized as transportation revenue when the customer's transported commodities reach their destination and is recorded at the fair value of the product received on the date received or the contract date, as applicable.

Product sales revenue pricing is contractually specified, and we have determined that each barrel sold represents a separate performance obligation. Transaction prices for our other services including terminalling, storage and ancillary services are typically contracted as a single performance obligation with our customers. In circumstances where multiple performance obligations are contractually required, we allocate the transaction price to the various performance obligations based on their relative standalone selling price.

Statement of Income Disclosures

The following tables provide details of our revenues disaggregated by key activities that comprise our performance obligations by operating segment (in thousands):

	Year Ended December 31, 2018			
	Refined Products	Crude Oil	Intersegment Eliminations	Total
Transportation	$ 749,266	$ 337,690	$ —	$ 1,086,956
Terminalling	182,648	6,365	—	$ 189,013
Storage	220,874	135,259	(3,691)	$ 352,442
Ancillary services	136,122	26,151	—	$ 162,273
Lease revenue	27,706	60,598	—	$ 88,304
Transportation and terminals revenue	1,316,616	566,063	(3,691)	1,878,988
Product sales revenue	880,453	46,767	—	$ 927,220
Affiliate management fee revenue	5,533	14,832	—	$ 20,365
Total revenue	2,202,602	627,662	(3,691)	2,826,573
Revenue not under the guidance of ASC 606:				
Lease revenue(1)	(27,706)	(60,598)	—	$ (88,304)
(Gains) losses from futures contracts included in product sales revenue(2)	(85,643)	632	—	$ (85,011)
Affiliate management fee revenue	(5,533)	(14,832)	—	$ (20,365)
Total revenue from contracts with customers under ASC 606	$ 2,083,720	$ 552,864	$ (3,691)	$ 2,632,893

(1) Lease revenue is accounted for under ASC 840, *Leases*.
(2) The impact on product sales revenue from futures contracts falls under the guidance of ASC 815, *Derivatives and Hedging*.

	Year Ended December 31, 2019			
	Refined Products	Crude Oil	Intersegment Eliminations	Total
Transportation	$ 778,394	$ 343,782	$ —	$ 1,122,176
Terminalling	185,008	17,822	—	$ 202,830
Storage	224,336	157,202	(5,417)	$ 376,121
Ancillary services	140,055	28,376	—	$ 168,431
Lease revenue	27,889	73,183	—	$ 101,072
Transportation and terminals revenue	1,355,682	620,365	(5,417)	1,970,630
Product sales revenue	707,812	28,280	—	$ 736,092
Affiliate management fee revenue	6,719	14,471	—	$ 21,190
Total revenue	2,070,213	663,116	(5,417)	2,727,912
Revenue not under the guidance of ASC 606:				
Lease revenue[1]	(27,889)	(73,183)	—	$ (101,072)
(Gains) losses from futures contracts included in product sales revenue[2]	69,538	3,024	—	$ 72,562
Affiliate management fee revenue	(6,719)	(14,471)	—	$ (21,190)
Total revenue from contracts with customers under ASC 606	$ 2,105,143	$ 578,486	$ (5,417)	$ 2,678,212

(1) Lease revenue is accounted for under ASC 842, *Leases*.
(2) The impact on product sales revenue from futures contracts falls under the guidance of ASC 815, *Derivatives and Hedging*.

Balance Sheet Disclosures

We invoice customers on our refined products pipelines for transportation services when their product enters our system. At each period end, we record all invoiced amounts associated with products that have not yet been delivered (in-transit products) as a contract liability. This liability is presented as deferred revenue on our consolidated balance sheets. Deferred revenue is also recorded for pre-payments received in conjunction with take-or-pay contracts, storage contracts and other service offerings in which the service to our customers remains unfulfilled. Additionally, at each period end, we defer the direct costs we have incurred associated with our customers' in-transit products as contract assets. Contract assets are presented on our consolidated balance sheets as other current assets. These direct costs are estimated based on our per-barrel direct delivery cost for the current period multiplied by the total in-transit barrels in our system at the end of the period multiplied by 50% to reflect the average transportation costs incurred for all products across all of our pipeline systems. We use 50% of the in-transit barrels because that best represents the average delivery point of all barrels in our pipeline system. These contract assets and contract liabilities are determined using judgments and assumptions that management considers reasonable.

The following table summarizes our accounts receivable, contract assets and contract liabilities resulting from contracts with customers (in thousands):

	December 31, 2018	December 31, 2019
Accounts receivable from contracts with customers	$ 102,684	$ 124,701
Contract assets	$ 8,487	$ 8,071
Contract liabilities	$ 122,129	$ 111,670

For the year ended December 31, 2019, we recognized $91.4 million of transportation and terminals revenue that was recorded in deferred revenue as of December 31, 2018.

Unfulfilled Performance Obligations

We have certain contracts with customers that represent customer commitments to purchase a minimum amount of our services over specified time periods. These contracts require us to provide services to our customers in the future and result in our having unfulfilled performance obligations ("UPOs") to our customers related to the periods remaining under each contract. We have UPOs in many of our core business services, including transportation, terminalling and storage services. The UPOs will be recognized as revenue in the future as our customers utilize our services or when we estimate that our customers are not likely to use all or a portion of their commitments.

The following table provides the aggregate amount of the transaction price allocated to our UPOs as of December 31, 2019 by operating segment, including the range of years remaining on our contracts with customers and an estimate of revenues expected to be recognized over the next 12 months (dollars in thousands):

	Refined Products	Crude Oil	Total
Balances at December 31, 2019	$ 2,245,549	$ 1,154,596	$ 3,400,145
Remaining terms	1 - 19 years	1 - 10 years	
Estimated revenues from UPOs to be recognized in the next 12 months	$ 423,974	$ 308,454	$ 732,428

In computing the value of these future revenues, we have used the current rates in effect as of December 31, 2019 and have not included any estimates for future rate changes due to changes in the FERC index or other contractually negotiated rate escalations. Our UPO balances include the full amount of our customer commitments as of December 31, 2019 through the expiration of the related contracts. The UPO balances disclosed exclude all performance obligations for which the original expected term is one year or less, the consideration is variable or the future use of our services is fully at the discretion of our customers.

5. Property, Plant and Equipment, Goodwill and Other Intangibles

Property, Plant and Equipment

Property, plant and equipment consist primarily of pipeline, pipeline-related equipment, storage tanks and processing equipment. We state property, plant and equipment at cost except for certain acquired assets recorded at fair value on their respective acquisition dates and impaired assets. We record impaired assets at fair value on the last impairment evaluation date for which an adjustment was required.

We assign asset lives based on reasonable estimates when we place an asset into service. Subsequent events could cause us to change our estimates, which would affect the future calculation of depreciation expense.

When we sell or retire property, plant and equipment, we remove its carrying value and the related accumulated depreciation from our accounts and record any associated gains or losses on our consolidated statements of income in the period of sale or disposition.

We capitalize expenditures to replace existing assets and retire the replaced assets. We capitalize expenditures when they extend the useful life, increase the productivity or capacity or improve the safety or efficiency of the asset. We capitalize direct project costs such as labor and materials as incurred. Indirect project costs, such as overhead, are capitalized based on a percentage of direct labor charged to the respective capital project. We charge expenditures for maintenance, repairs and minor replacements to operating expense in the period incurred.

During construction, we capitalize interest on all construction projects requiring a completion period of three months or longer and total project costs exceeding $0.5 million. The interest we capitalize is based on the weighted-average interest rate of our debt. The weighted average rates used to capitalize interest on borrowed funds were 4.8%, 4.8% and 4.6% for the years ended December 31, 2017, 2018 and 2019, respectively.

Property, plant and equipment consisted of the following (in thousands):

	December 31,		Estimated
	2018	2019	Depreciable Lives
Construction work-in-progress	$ 395,184	$ 515,312	
Land and rights-of-way	303,485	336,982	
Buildings	119,720	125,772	10 to 53 years
Storage tanks	2,059,244	2,206,839	10 to 40 years
Pipeline and station equipment	2,614,855	2,917,059	10 to 59 years
Processing equipment	1,875,029	2,044,589	3 to 56 years
Other	261,075	284,674	3 to 53 years
Property, Plant and Equipment, Gross	$ 7,628,592	$ 8,431,227	

Other includes total interest capitalized on construction in progress as of December 31, 2018 and 2019 of $67.6 million and $86.4 million, respectively. Depreciation expense for the years ended December 31, 2017, 2018 and 2019 was $196.3 million, $214.4 million and $242.9 million, respectively.

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. In reviewing for impairment, the carrying value of such assets is compared to the estimated undiscounted future cash flows expected from the use of the assets and their eventual disposition. If such cash flows are not sufficient to support the asset's recorded value, an impairment charge is recognized to reduce the carrying value of the long-lived asset to its estimated fair value. The determination of future cash flows as well as the estimated fair value of long-lived assets involves significant estimates on the part of management.

During 2018, we made the decision to discontinue commercial operations of our ammonia pipeline due to the system's low profitability and challenging economic outlook. We estimated the fair value of the ammonia pipeline assets based on expected future cash flows and recognized a $49.1 million impairment charge in depreciation, amortization and impairment expense on our consolidated statements of income in 2018.

Goodwill

We record the excess of purchase price over the fair value of the tangible and identifiable intangible assets acquired and liabilities assumed in a business acquisition (or combination) as goodwill. The goodwill relating to each of our reporting units is tested for impairment annually as well as when an event or change in circumstances indicates an impairment may have occurred.

For purposes of performing the impairment test for goodwill, our reporting units are our refined products and crude oil segments. In 2017 and 2018, we elected to complete the quantitative goodwill impairment test and calculated that the fair value of each of our reporting units was greater than its carrying amount. In 2019, we elected to perform the qualitative assessment for purposes of our annual goodwill impairment test and concluded that it was more likely than not that the fair value of each of our reporting units was greater than its carrying amount. Based on this assessment, we concluded goodwill was not impaired.

Other Intangibles

Other intangible assets with finite lives are amortized over their estimated useful lives of seven years up to 30 years. The weighted-average asset life of our other intangible assets at December 31, 2019 was approximately 19 years. We adjust the useful lives of our other intangible assets if events or circumstances indicate there has been a change in the remaining useful lives. We eliminate from our balance sheets the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized. During the years ended December 31, 2017, 2018 and 2019, amortization of other intangible assets was $0.4 million, $1.6 million and $3.3 million, respectively.

6. Investments in Non-Controlled Entities

We account for interests in affiliates that we do not control using the equity method of accounting. Under this method, an investment is recorded at our acquisition cost or capital contributions, as adjusted by contractual terms, plus equity in earnings or losses since acquisition or formation, plus interest capitalized, less distributions received and amortization of interest capitalized and excess net investment. Excess net investment is the amount by which our investment in a non-controlled entity exceeded our proportionate share of the book value of the net assets of that investment. We amortize excess net investment over the weighted-average depreciable asset lives of the equity investee. Our unamortized excess net investment was $34.8 million and $33.9 million at December 31, 2018 and 2019, respectively. The amount of unamortized excess investment is primarily related to our investment in BridgeTex. We evaluate equity method investments for impairment whenever events or circumstances indicate that there is an other-than-temporary loss in value of the investment. In the event that we determine that the loss in value of an investment is other-than-temporary, we would record a charge to earnings to adjust the carrying value to fair value. We recognized no equity investment impairments during 2017, 2018 and 2019.

Our investments in non-controlled entities at December 31, 2019 were comprised of:

Entity	Ownership Interest
BridgeTex Pipeline Company, LLC ("BridgeTex")	30%
Double Eagle Pipeline LLC ("Double Eagle")	50%
HoustonLink Pipeline Company, LLC ("HoustonLink")	50%
MVP Terminalling, LLC ("MVP")	50%
Powder Springs Logistics, LLC ("Powder Springs")	50%
Saddlehorn Pipeline Company, LLC ("Saddlehorn")	40%
Seabrook Logistics, LLC ("Seabrook")	50%
Texas Frontera, LLC ("Texas Frontera")	50%

We serve as operator of BridgeTex, HoustonLink, MVP, Powder Springs, Saddlehorn, Texas Frontera and the pipeline activities of Seabrook. We receive fees for management services as well as reimbursement or payment to us for certain direct operational payroll and other overhead costs. The management fees we receive are reported as affiliate management fee revenue on our consolidated statements of income. Cost reimbursements we receive from these entities in connection with our operating services are included as reductions to costs and expenses on our consolidated statements of income and totaled \$3.6 million, \$3.9 million and \$5.3 million, respectively, for the years ended December 31, 2017, 2018 and 2019.

We recorded the following revenue and expense transactions from certain of these non-controlled entities in our consolidated statements of income (in thousands):

	Year Ended December 31,		
	2017	2018	2019
Transportation and terminals revenue:			
BridgeTex, capacity lease	$ 36,129	$ 39,596	$ 41,806
Double Eagle, throughput revenue	$ 4,673	$ 5,250	$ 6,213
Saddlehorn, storage revenue	$ 2,126	$ 2,180	$ 2,234
Operating costs:			
Seabrook, storage lease and ancillary services	$ —	$ 10,572	$ 25,851
MVP, sale of air emission reduction credits (reduction of operating costs)	$ —	$ (2,161)	$ —
Product sales revenue:			
Powder Springs, butane sales	$ —	$ 4,899	$ —
Seabrook, product sales	$ —	$ —	$ 328
Cost of product sales:			
BridgeTex, transportation charges	$ 14,450	$ —	$ —
Powder Springs, butane purchases	$ —	$ 410	$ —
Other income:			
MVP, easement sale	$ —	$ —	$ 289

Our consolidated balance sheets reflected the following balances related to our investments in non-controlled entities (in thousands):

	December 31, 2018			
	Trade Accounts Receivable	Other Accounts Receivable	Other Accounts Payable	Long-Term Receivables
BridgeTex	$ 318	$ 1,549	$ —	$ —
Double Eagle	$ 546	$ —	$ —	$ —
MVP	$ —	$ 397	$ —	$ —
Powder Springs	$ —	$ —	$ —	$ 2,221
Saddlehorn	$ —	$ 183	$ —	$ —
Seabrook	$ —	$ —	$ 1,140	$ —

	December 31, 2019			
	Trade Accounts Receivable	Other Accounts Receivable	Other Accounts Payable	Long-Term Receivables
BridgeTex	$ 392	$ 26	$ —	$ —
Double Eagle	$ 445	$ —	$ —	$ —
HoustonLink	$ 60	$ —	$ —	$ —
MVP	$ —	$ 418	$ —	$ —
Powder Springs	$ 161	$ —	$ —	$ 6,006
Saddlehorn	$ —	$ 126	$ —	$ —
Seabrook	$ 941	$ —	$ 1,349	$ —

We entered into a long-term terminalling and storage contract with Seabrook for exclusive use of dedicated tankage that provides our customers with crude oil storage capacity and dock access for crude oil imports and exports on the Texas Gulf Coast (see Note 10 – *Leases* for more details regarding this lease).

The financial results from Powder Springs, MVP and Texas Frontera are included in our refined products segment and the financial results from BridgeTex, Double Eagle, HoustonLink, Saddlehorn and Seabrook are included in our crude oil segment, each as earnings of non-controlled entities.

A summary of our investments in non-controlled entities (representing only our proportionate interests) follows (in thousands):

Investments at December 31, 2018	$ 1,076,306
Additional investment	212,380
Indemnification settlement	(5,000)
Earnings of non-controlled entities:	
Proportionate share of earnings	170,814
Amortization of excess investment and capitalized interest	(1,853)
Earnings of non-controlled entities	168,961
Less:	
Distributions from operations of non-controlled entities	203,602
Distributions from returns of investments in non-controlled entities	8,494
Investments at December 31, 2019	$ 1,240,551

Summarized financial information of our non-controlled entities (representing 100% of the interests in these entities) follows (in thousands):

	December 31,	
	2018	2019
Current assets	$ 258,698	$ 260,033
Noncurrent assets	2,461,456	2,768,696
Total assets	$ 2,720,154	$ 3,028,729
Current liabilities	$ 170,558	$ 160,566
Noncurrent liabilities	73,700	60,886
Total liabilities	$ 244,258	$ 221,452
Equity	$ 2,475,896	$ 2,807,277

	Year Ended December 31,		
	2017	2018	2019
Revenue	$ 419,214	$ 631,420	$ 782,013
Net income	$ 256,423	$ 416,128	$ 507,464

7. Inventory

Inventory is comprised primarily of refined products, liquefied petroleum gases, transmix, crude oil and additives, which are stated and relieved at the lower of average cost or net realizable value.

Inventory at December 31, 2018 and 2019 was as follows (in thousands):

	December 31,	
	2018	2019
Refined products	$ 92,751	$ 96,128
Liquefied petroleum gases	46,612	29,982
Transmix	28,497	39,546
Crude oil	11,220	12,714
Additives	6,655	6,029
Total inventory	$ 185,735	$ 184,399

During 2018 and 2019, we recorded lower of average cost or net realizable value adjustments of $18.5 million and $4.8 million, respectively, related to our refined products, transmix and crude oil inventories.

8. Consolidated Statements of Cash Flows

Changes in the components of operating assets and liabilities are as follows (in thousands):

	Year Ended December 31,		
	2017	2018	2019
Trade accounts receivable and other accounts receivable	$ (25,639)	$ 24,169	$ (20,156)
Inventory	(47,967)	(3,390)	1,336
Accounts payable	8,954	21,146	(1,237)
Accrued payroll and benefits	10,596	14,015	4,931
Accrued interest payable	5,014	(7,399)	1,018
Accrued taxes other than income	1,177	1,750	12,914
Deferred revenue	15,904	5,191	(11,431)
Accrued product liabilities	44,559	(20,677)	15,306
Other current and noncurrent assets and liabilities	3,097	(12,559)	5,313
Total	$ 15,695	$ 22,246	$ 7,994

Other current and noncurrent assets and liabilities above exclude certain non-cash items that were reflected in the consolidated balance sheets but were not reflected in the statements of cash flows. At December 31, 2017, 2018 and 2019, the long-term pension and benefits liability was increased by $46.0 million, $2.3 million and $27.0 million, respectively, resulting in a corresponding increase in accumulated other comprehensive loss ("AOCL").

9. Debt

Long-term debt at December 31, 2018 and 2019 was as follows (in thousands):

	December 31, 2018	December 31, 2019
6.55% Notes due 2019[1]	$ 550,000	$ —
4.25% Notes due 2021	550,000	550,000
3.20% Notes due 2025	250,000	250,000
5.00% Notes due 2026	650,000	650,000
6.40% Notes due 2037	250,000	250,000
4.20% Notes due 2042	250,000	250,000
5.15% Notes due 2043	550,000	550,000
4.20% Notes due 2045	250,000	250,000
4.25% Notes due 2046	500,000	500,000
4.20% Notes due 2047	500,000	500,000
4.85% Notes due 2049	—	500,000
3.95% Notes due 2050	—	500,000
Face value of long-term debt	4,300,000	4,750,000
Unamortized debt issuance costs[2]	(27,070)	(35,263)
Net unamortized debt discount[2]	(2,927)	(8,662)
Net unamortized amount of gains from historical fair value hedges[2]	866	—
Long-term debt, net, including current portion	4,270,869	4,706,075
Less: current portion of long-term debt, net[1]	59,489	—
Long-term debt, net	$ 4,211,380	$ 4,706,075

(1) At December 31, 2018, we had the ability and the intent to refinance approximately $490.0 million of our long-term notes maturing in 2019. As a result, only the portion of our debt intended to be repaid with cash available as of December 31, 2018 was classified as current in our consolidated balance sheets.

(2) Debt issuance costs, note discounts and premiums and realized gains and losses of historical fair value hedges are being amortized or accreted to the applicable notes over the respective lives of those notes.

All of the instruments detailed in the table above are senior indebtedness.

At December 31, 2019, maturities of our debt were as follows: $0 in 2020; $550 million in 2021; $0 in 2022; $0 in 2023; $0 in 2024; and $4.2 billion thereafter.

2019 Debt Issuances

On August 19, 2019, we issued $500.0 million of 3.95% senior notes due 2050 in an underwritten public offering. The notes were issued at 99.91% of par. Net proceeds from this offering were approximately $494.4 million after underwriting discounts and offering expenses. The net proceeds from this offering were used for general partnership purposes, including expansion capital projects.

On January 18, 2019, we issued $500.0 million of 4.85% senior notes due 2049 in an underwritten public offering. The notes were issued at 99.371% of par. Net proceeds from this offering were approximately $491.5 million after underwriting discounts and offering expenses. The net proceeds from this offering along with cash on hand were used to redeem our $550.0 million of 6.55% senior notes due 2019 on February 11, 2019, prior to maturity. In connection with this offering, we recognized $8.3 million of debt prepayment costs that were recorded as interest expense in our consolidated statements of income.

Other Debt

Revolving Credit Facility. At December 31, 2019, the total borrowing capacity under our revolving credit facility maturing in May 2024 was $1.0 billion. Any borrowings outstanding under this facility are classified as long-term debt on our consolidated balance sheets. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 1.000% to 1.625% based on our credit ratings. Additionally, an unused commitment fee is assessed at a rate from 0.100% to 0.275% depending on our credit ratings. The unused commitment fee was 0.125% at December 31, 2019. Borrowings under this facility may be used for general purposes, including capital expenditures. As of December 31, 2018 and 2019, respectively, there were obligations for letters of credit of $6.8 million and $3.5 million, respectively. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets, but decrease our borrowing capacity under the facility. There were no borrowings outstanding under this facility at December 31, 2018 and 2019.

Our revolving credit facility requires us to maintain a specified ratio of consolidated debt to EBITDA (as defined in the credit agreement) of no greater than 5.0 to 1.0. In addition, the revolving credit facility and the indentures under which our senior notes were issued contain covenants that limit our ability to, among other things, incur indebtedness secured by certain liens or encumber our assets, engage in certain sale-leaseback transactions and consolidate, merge or dispose of all or substantially all of our assets. We were in compliance with these covenants as of and during the year ended December 31, 2019.

Commercial Paper Program. We have a commercial paper program under which we may issue commercial paper notes in an amount up to the available capacity under our $1.0 billion revolving credit facility. The maturities of the commercial paper notes vary, but may not exceed 397 days from the date of issuance. Because the commercial paper we can issue is limited to amounts available under our revolving credit facility, amounts outstanding under the program are classified as long-term debt. The commercial paper notes are sold under customary terms in the commercial paper market and are issued at a discount from par, or alternatively, are sold at par and bear varying interest rates on a fixed or floating basis. The weighted-average interest rate for commercial paper borrowings based on the number of days outstanding was 2.3% and 2.6%, respectively, for the year ended December 31, 2018 and 2019.

364-Day Revolving Credit Facility. In May 2019, we entered into a $500 million 364-day revolving credit facility. We did not make any borrowings under this agreement, which was terminated in January 2020.

During the years ending December 31, 2017, 2018 and 2019, total cash payments for interest on all indebtedness, excluding the impact of related interest rate swap agreements, were $206.2 million, $227.8 million and $217.1 million, respectively.

10. Leases

As of January 1, 2019, we adopted ASU 2016-02, *Leases (Topic 842)* using the modified retrospective method of adoption. We elected to use the transition option that allows us to initially apply the new lease standard at the adoption date and recognize a cumulative-effect adjustment, if any, to the opening balance of retained earnings in the year of adoption. Comparable periods continue to be presented under the guidance of the previous standard, ASC 840. ASC 842 requires lessees to recognize a lease liability and right-of-use asset on the balance sheet for operating leases. For lessors, the new accounting model remains largely the same, although some changes have been made to align it with the new lessee model and the new revenue recognition guidance, ASC 606, *Revenue from Contracts with Customers*. Our adoption of ASC 842 did not result in any material adjustments to retained earnings, changes in the timing or amounts of lease costs or changes to our leverage ratio as defined in our credit agreement.

We have both lessee and lessor arrangements. Our leases are evaluated at inception or at any subsequent modification. Depending on the terms, leases are classified as either operating or finance leases if we are the lessee, or as operating, sales-type or direct financing leases if we are the lessor, as appropriate under ASC 842. Our lessee arrangements primarily include a terminalling and storage contract where we have exclusive use of dedicated tankage, leased pipelines and office buildings. Our lessor arrangements include pipeline capacity and storage contracts and our condensate splitter tolling agreement that qualify as operating leases under ASC 842. In addition, we have a long-term throughput and deficiency agreement with a customer that is being accounted for as a sales-type lease under ASC 842.

In accordance with ASC 842, we have made an accounting policy election to not apply the new standard to lessee arrangements with a term of one year or less and no purchase option that is reasonably certain of exercise. We will continue to account for these short-term arrangements by recognizing payments and expenses as incurred, without recording a lease liability and right-of-use asset.

We have also made an accounting policy election for both our lessee and lessor arrangements to combine lease and non-lease components. This election is applied to all of our lease arrangements as our non-lease components do not result in significant timing differences in the recognition of rental expenses or income.

Operating Leases – Lessee

We recognize a lease liability for each lease based on the present value of remaining minimum fixed rental payments (which includes payments under any renewal option that we are reasonably certain to exercise), using a discount rate that approximates the rate of interest we would have to pay to borrow on a collateralized basis over a similar term. We also recognize a right-of-use asset for each lease, valued at the lease liability, adjusted for prepaid or accrued rent balances existing at the time of initial recognition. The lease liability and right-of-use asset are reduced over the term of the lease as payments are made and the assets are used.

Related Party Operating Lease. We entered into a long-term terminalling and storage contract with Seabrook for exclusive use of dedicated tankage that provides our customers with crude oil storage capacity and dock access for crude oil imports and exports on the Texas Gulf Coast.

Minimum fixed rental payments are recognized on a straight-line basis over the life of the lease as costs and expenses on our consolidated statements of income. Variable and short-term rental payments are recognized as costs and expenses as they are incurred. Variable payments consist of amounts that exceed the contractual minimum rental payment (for example, payment increases tied to a change in a market index). Future minimum rental payments under operating leases with initial terms greater than one year as of December 31, 2019 are as follows (in thousands):

	Third Party Leases	Seabrook Lease	All Leases
2020	$ 18,607	$ 13,735	$ 32,342
2021	18,993	12,280	31,273
2022	18,869	9,919	28,788
2023	18,348	9,919	28,267
2024	14,341	9,643	23,984
Thereafter	19,748	30,858	50,606
Total future minimum rental payments	108,906	86,354	195,260
Present value discount	12,262	$ 12,754	$ 25,016
Total operating lease liability	$ 96,644	$ 73,600	$ 170,244

The following tables provide further information about our operating leases (dollars in thousands):

	Year Ended December 31, 2019		
	Third Party Leases	Seabrook Lease	All Leases
Fixed lease cost	$ 19,171	$ 10,834	$ 30,005
Short-term lease cost	1,603	—	1,603
Variable lease cost	3,058	15,017	18,075
Total lease cost	$ 23,832	$ 25,851	$ 49,683

	As of and for the Year Ended December 31, 2019		
	Third Party Leases	Seabrook Lease	All Leases
Current lease liability	$ 15,136	$ 11,085	$ 26,221
Long-term lease liability	$ 81,508	$ 62,515	$ 144,023
Right-of-use asset	$ 98,268	$ 73,600	$ 171,868
Operating cash flows for operating leases	$ 23,253	25,870	$ 49,123
Weighted average remaining lease term (years)	6	8	7
Weighted-average discount rate	3.9%	4.0%	4.0%

Rent expense was $34.8 million and $42.1 million, respectively, for years ended December 31, 2017 and 2018 and was recognized in accordance with ASC 840.

Operating Leases – Lessor

We recognize fixed rental income on a straight-line basis over the life of the lease as revenue on our consolidated statements of income. Variable rental payments are recognized as revenue in the period in which the circumstances on which the variable lease payments are based occur.

Future minimum payments receivable under operating leases with initial terms greater than one year as of December 31, 2019 are estimated as follows (in thousands):

2020	$	47,687
2021		48,497
2022		35,569
2023		18,557
2024		18,296
Thereafter		54,472
Total	$	223,078

We recognized variable lease revenue of $24.9 million, $51.8 million and $58.4 million, respectively, for the years ended December 31, 2017, 2018 and 2019, primarily related to our condensate splitter.

At December 31, 2019, property, plant and equipment utilized by our customers in operating lease arrangements consisted of: $231.2 million of processing equipment; $77.4 million of storage tanks; $49.8 million of pipeline and station equipment; and $32.1 million of other assets. The processing equipment primarily relates to our condensate splitter.

Sales-Type Lease – Lessor

We entered into a long-term throughput and deficiency agreement with a customer on a pipeline and related assets that we constructed in Texas and New Mexico, which contains minimum volume/payment commitments. Our customer has the option to purchase this pipeline and related assets at the end of the lease term for a nominal amount. This agreement was previously accounted for as a direct-financing lease under ASC 840 and is now being accounted for s a sales-type lease under ASC 842. The net investment under this arrangement as of December 31, 2018 and 2019 was as follows (in thousands):

	December 31, 2018		December 31, 2019	
Total minimum lease payments receivable	$	17,468	$	15,721
Less: Unearned income		3,422		2,814
Recorded net investment in direct financing lease	$	14,046	$	12,907

The net investment in direct financing leases was classified in the consolidated balance sheets as follows (in millions):

	December 31, 2018		December 31, 2019	
Other accounts receivable	$	1,138	$	1,190
Long-term receivables		12,908		11,717
Total	$	14,046	$	12,907

Future minimum payments receivable under this direct financing lease for the next five years are $1.7 million each year with $7.0 million due thereafter.

11. Employee Benefit Plans

Our pension and postretirement benefit liabilities represent the funded status of the present value of benefit obligations of our employee benefit plans. We develop pension, postretirement medical and life benefit costs from third-party actuarial valuations. We establish actuarial assumptions to anticipate future events and use those assumptions when calculating the expense and liabilities related to these plans. These factors include assumptions management makes concerning expected investment return on plan assets, discount rates, health care costs trend rates, turnover rates and rates of future compensation increases, among others. In addition, we use subjective factors such as withdrawal and mortality rates to develop actuarial valuations. Management reviews and updates these assumptions on an annual basis. The actuarial assumptions that we use may differ from actual results due to changing market rates or other factors. These differences could affect the amount of pension and postretirement medical and life benefit expense we will recognize in future periods.

Defined Contribution Plan. We sponsor a defined contribution plan in which we match our employees' qualifying contributions, resulting in additional expense to us. Expenses related to the defined contribution plan were $9.9 million, $11.0 million and $11.4 million in 2017, 2018 and 2019, respectively.

Defined Benefit Plans. We sponsor two union pension plans that cover certain union employees ("USW plan" and "IUOE plan," collectively, the "Union plans"), a pension plan for all non-union employees ("Salaried plan") and a postretirement benefit plan for certain employees. The annual measurement date of these plans is December 31.

The following table presents the changes in benefit obligations and plan assets for pension benefits and other postretirement benefits, as well as the end-of-period accumulated benefit obligation for the years ended December 31, 2018 and 2019 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2018	2019	2018	2019
Change in benefit obligations:				
Benefit obligations at beginning of year	$ 297,856	$ 308,949	$ 12,760	$ 12,080
Service cost	38,167	25,406	243	193
Interest cost	14,907	12,163	416	507
Plan participants' contributions	—	—	357	564
Actuarial (gain) loss	(21,375)	54,171	(599)	3,300
Benefits paid	(14,356)	(11,409)	(1,097)	(1,437)
Settlement payments	(6,250)	(8,040)	—	—
Benefit obligations at end of year	308,949	381,240	12,080	15,207
Change in plan assets:				
Fair value of plan assets at beginning of year	198,686	197,590	—	—
Employer contributions	31,717	31,630	740	873
Plan participants' contributions	—	—	357	564
Actual (loss) return on plan assets	(12,207)	39,522	—	—
Benefits paid	(14,356)	(11,409)	(1,097)	(1,437)
Settlement payments	(6,250)	(8,040)	—	—
Fair value of plan assets at end of year	197,590	249,293	—	—
Funded status at end of year	$ (111,359)	$ (131,947)	$ (12,080)	$ (15,207)
Accumulated benefit obligations	$ 208,840	$ 274,353		

At December 31, 2018 and 2019, the accumulated benefit obligations of each of our plans exceeded the fair value of the related plans' assets.

The pension benefit obligations experienced an actuarial loss of $54.2 million in 2019 primarily due to the impact of decreases in the discount rates used to calculate the benefit obligations, partially offset by changes in salary assumptions and higher asset returns.

Amounts recognized in the consolidated balance sheets included in these financial statements were as follows (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2018	2019	2018	2019
Amounts recognized in consolidated balance sheets:				
Current accrued benefit cost	$ —	$ —	$ 859	$ 1,162
Long-term pension and benefits	111,359	131,947	11,221	14,045
	111,359	131,947	12,080	15,207
Accumulated other comprehensive loss:				
Net actuarial loss	(91,669)	(107,625)	(5,409)	(8,378)
Prior service credit	3,067	2,886	—	—
	(88,602)	(104,739)	(5,409)	(8,378)
Net amount of liabilities and accumulated other comprehensive loss recognized in consolidated balance sheets	$ 22,757	$ 27,208	$ 6,671	$ 6,829

Net periodic benefit expense for the years ended December 31, 2017, 2018 and 2019 was as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2017	2018	2019	2017	2018	2019
Components of net periodic pension and postretirement benefit expense:						
Service cost	$ 20,497	$ 38,167	$ 25,406	$ 243	$ 243	$ 193
Interest cost	9,865	14,907	12,163	475	416	507
Expected return on plan assets	(10,266)	(12,090)	(9,401)	—	—	—
Amortization of prior service credit	(181)	(181)	(181)	—	—	—
Amortization of actuarial loss	5,622	9,763	5,489	749	589	331
Settlement cost	2,460	1,964	2,606	—	—	—
Net periodic expense	$ 27,997	$ 52,530	$ 36,082	$ 1,467	$ 1,248	$ 1,031

The service component of our net periodic benefit expense (credit) is presented in operating expense and G&A expense, and the non-service components are presented in other (income) expense in our consolidated statements of income.

Net periodic benefit expense for the year ended December 31, 2018 includes corrections of $19.4 million resulting from an error in our third-party actuary's valuation of our pension liabilities and net periodic pension expense. In addition, long-term pension and benefits increased $22.2 million and accumulated other comprehensive loss increased $2.8 million in our 2018 consolidated balance sheets as a result of this valuation error.

Changes in plan assets and benefit obligations recognized in other comprehensive income (loss) during 2017, 2018 and 2019 were as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2017	2018	2019	2017	2018	2019
Beginning balance	$ (58,584)	$ (97,226)	$ (88,602)	$ (7,881)	$ (6,597)	$ (5,409)
Net actuarial gain (loss)	(46,543)	(2,922)	(24,051)	535	599	(3,300)
Amortization of prior service credit	(181)	(181)	(181)	—	—	—
Amortization of actuarial loss	5,622	9,763	5,489	749	589	331
Settlement cost	2,460	1,964	2,606	—	—	—
Amount recognized in other comprehensive loss	(38,642)	8,624	(16,137)	1,284	1,188	(2,969)
Ending balance	$ (97,226)	$ (88,602)	$ (104,739)	$ (6,597)	$ (5,409)	$ (8,378)

Actuarial gains and losses are amortized over the average future service period of the current active plan participants expected to receive benefits. The corridor approach is used to determine when actuarial gains and losses are to be amortized and is equal to 10% of the greater of the projected benefit obligation or the market related value of plan assets. The amount of gain or loss in excess of the calculated corridor is subject to amortization. The estimated net actuarial loss and prior service credit for the defined benefit pension plans that will be amortized from AOCL into net periodic benefit cost in 2020 are $5.7 million and $0.2 million, respectively. The estimated net actuarial loss for the other defined benefit postretirement plan that will be amortized from AOCL into net periodic benefit cost in 2020 is $0.5 million.

The weighted-average rate assumptions used to determine projected benefit obligations were as follows:

	December 31,	
	2018	2019
Discount rate—Salaried plan	3.99%	3.02%
Discount rate—USW plan	3.94%	2.96%
Discount rate—IUOE plan	4.12%	3.09%
Discount rate—Other Postretirement Benefits	4.08%	3.06%
Rate of compensation increase—Salaried plan	6.90%	4.72%
Rate of compensation increase—USW plan	3.50%	3.28%
Rate of compensation increase—IUOE plan	5.00%	4.78%

The weighted-average rate assumptions used to determine net pension and other postretirement benefit plans expense were as follows:

	For the Year Ended December 31,		
	2017	2018	2019
Discount rate—Salaried plan	4.21%	3.70%	3.99%
Discount rate—USW plan	4.04%	3.63%	3.73%
Discount rate—IUOE plan	4.41%	3.79%	4.12%
Discount rate—Other Postretirement Benefits	3.85%	3.43%	4.08%
Rate of compensation increase—Salaried plan	4% - 11%	6.80%	6.90%
Rate of compensation increase—USW plan	3.50%	3.50%	3.50%
Rate of compensation increase—IUOE plan	5.00%	5.00%	5.00%
Expected rate of return on plan assets—Salaried plan	6.00%	6.00%	4.60%
Expected rate of return on plan assets—USW plan	6.00%	6.00%	4.60%
Expected rate of return on plan assets—IUOE plan	6.00%	6.00%	4.70%

The non-pension postretirement benefit plans provide for retiree contributions and contain other cost-sharing features such as deductibles and coinsurance. The accounting for these plans anticipates future cost sharing that is consistent with management's expressed intent to increase the retiree contribution rate generally in line with health care cost increases.

The annual assumed rate of increase in the health care cost trend rate for 2020 is 6.0% decreasing systematically to 5.08% by 2027 for pre-65 year old participants. As of December 31, 2019, a 1.0% change in assumed health care cost trend rates would be immaterial.

The fair values of the pension plan assets at December 31, 2018 were as follows (in thousands):

Asset Category	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Equity Securities[1]:				
Small-cap fund	$ 3,816	$ 3,816	$ —	$ —
Mid-cap fund	3,811	3,811	—	—
Large-cap fund	30,595	30,595	—	—
International equity fund	19,471	19,471	—	—
Fixed Income Securities[1]:				
Short-term bond fund	9,242	9,242	—	—
Intermediate-term bond fund	23,036	23,036	—	—
Long-term investment grade bond funds	99,118	99,118	—	—
Other:				
Short-term investment fund	8,312	8,312	—	—
Group annuity contract	189	—	—	189
Fair value of plan assets	$ 197,590	$ 197,401	$ —	$ 189

(1) We hold equity and fixed income securities through investments in mutual funds, which are dedicated to each category as indicated.

The fair values of the pension plan assets at December 31, 2019 were as follows (in thousands):

Asset Category	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Equity Securities[(1)]:				
Small-cap fund	$ 5,087	$ 5,087	$ —	$ —
Mid-cap fund	5,095	5,095	—	—
Large-cap fund	40,884	40,884	—	—
International equity fund	25,580	25,580	—	—
Fixed Income Securities[(1)]:				
Short-term bond fund	3,590	3,590	—	—
Intermediate-term bond fund	29,485	29,485	—	—
Long-term investment grade bond funds	132,096	132,096	—	—
Other:				
Short-term investment fund	7,300	7,300	—	—
Group annuity contract	176	—	—	176
Fair value of plan assets	$ 249,293	$ 249,117	$ —	$ 176

(1) We hold equity and fixed income securities through investments in mutual funds, which are dedicated to each category as indicated.

As reflected in the tables above, Level 3 activity was not material.

The investment strategies for the various funds held as pension plan assets by asset category are as follows:

Asset Category	Fund's Investment Strategy
Domestic Equity Securities:	
Small-cap fund	Seeks to track performance of the Center for Research in Security Prices ("CRSP") US Small Cap Index
Mid-cap fund	Seeks to track performance of the CRSP US Mid Cap Index
Large-cap fund	Seeks to track performance of the Standard & Poor's 500 Index
International equity fund	Seeks long-term growth of capital by investing 65% or more of assets in international equities
Fixed Income Securities:	
Short-term bond fund	Seeks current income with limited price volatility through investment in primarily high quality bonds
Intermediate-term bond fund	Seeks moderate and sustainable level of current income by investing primarily in high quality fixed income securities with maturities from five to ten years
Long-term investment grade bond funds	Seek high and sustainable current income through investment primarily in long-term high grade bonds
Other:	
Short-term investment fund	Invests in high quality short-term money market instruments issued by the U.S. Treasury
Group annuity contract	Earns interest quarterly equal to the effective yield of the 91-day U.S. Treasury bill

The expected long-term rate of return on plan assets was determined by combining a review of projected returns, historical returns of portfolios with assets similar to the current portfolios of the union and non-union pension plans and target weightings of each asset classification. Our investment objective for the assets within the pension plans is to earn a return that meets or exceeds the growth of obligations that result from interest and changes in the discount rate, while avoiding excessive risk. Defined diversification goals are set in order to reduce the risk of wide swings in the market value from year to year, or of incurring large losses that may result from concentrated positions. As a result, our plan assets have no significant concentrations of credit risk. Additionally, liquidity risks are minimized because all of the funds that the plans have invested in are publicly traded. We evaluate risks based on the potential impact to the predictability of contribution requirements, probability of under-funding, expected risk-adjusted returns and investment return volatility. Funds are invested with multiple investment managers. Our liabilities are calculated using rates defined by the Pension Protection Act of 2006. Approximately 70% of the plans' investments are allocated to fixed-income securities and invested to match the durations of the plans' short, intermediate and long-term pension liabilities, with the amount invested in each duration reflecting that duration's proportion of the plans' liabilities. The remaining approximately 30% of the plans' investments are allocated to equity securities.

The target allocation and actual weighted-average asset allocation percentages at December 31, 2018 and 2019 were as follows:

	2018		2019	
	Actual	Target	Actual	Target
Equity securities	29%	30%	30%	30%
Fixed income securities	67%	67%	67%	67%
Other	4%	3%	3%	3%

As of December 31, 2019, the benefit amounts expected to be paid from plan assets through December 31, 2029 were as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2020	$ 15,943	$ 1,163
2021	$ 16,473	$ 1,187
2022	$ 18,981	$ 1,141
2023	$ 21,445	$ 1,080
2024	$ 23,621	$ 938
2025 through 2029	$ 136,931	$ 4,069

Contributions estimated to be paid by us into the plans in 2020 are $31.3 million and $1.2 million for the pension and other postretirement benefit plans, respectively.

12. Long-Term Incentive Plan

The compensation committee of our general partner's board of directors administers our long-term incentive plan ("LTIP") covering certain of our employees and the independent directors of our general partner. The LTIP primarily consists of phantom units and permits the grant of awards covering an aggregate of 11.9 million of our common units. The estimated units remaining available under the LTIP at December 31, 2019 totaled approximately 1.6 million. The awards include: (i) performance-based awards issued to certain officers and other key employees ("performance-based awards"), (ii) time-based awards issued to certain officers and other key employees ("time-based awards," and together with performance-based awards, "employee awards"), and (iii) awards issued to independent members of our general partner's board of directors ("director awards") that may be deferred and if deferred may be paid in cash. All of the awards include distribution equivalent rights, except non-deferred director awards.

The LTIP requires employee awards to be settled in our common units, except the settlement of distribution equivalents, which we pay in cash. As a result, we classify employee awards as equity. Fair value for these awards is determined on the grant date, and we recognize this value as compensation expense ratably over the requisite service period, which is the vesting period of each award. The vesting period for employee awards is generally three years; however, certain awards have been issued with shorter vesting periods while others have vesting periods of up to four years. Because employee awards contain distribution equivalent rights, the fair value of our employee awards is based on the closing price of our units on the grant date.

Payouts for performance-based awards are subject to the attainment of a financial metric and to an adjustment for our total unitholder return (the "TUR adjustment"), and the fair value of these awards is adjusted for the fair value of the TUR adjustment. The financial metric for the performance-based awards is our distributable cash flow per unit excluding commodity-related activities for the last year of the three-year vesting period as compared to established threshold, target and stretch levels. The payouts for the performance-related component of the awards can range from 0% for results below threshold, up to 200% for actual results at stretch or above. The TUR adjustment is based on our total unitholder return at the end of the three-year vesting period of the awards in relation to the total unitholder returns of certain peer entities and can increase or decrease the payout of the award by as much as 50%. Payouts related to time-based awards are based solely on the completion of the requisite service period by the employee and contain no provisions that provide for a payout other than the original number of units awarded and the associated distribution equivalents.

Performance-based awards are subject to forfeiture if a participant's employment is terminated for any reason other than for termination within two years of a change-in-control that occurs on an involuntary basis without cause or on a voluntary basis for good cause, or due to retirement, disability or death prior to the vesting date. These awards can vest early under certain circumstances following a change in control. Time-based awards are subject to forfeiture if a participant's employment is terminated for any reason other than retirement, death or disability prior to the vesting date, or as the result of certain other employment restrictions. If an employee award recipient retires, dies or becomes disabled prior to the end of the vesting period, the award is prorated based upon months of employment completed during the vesting period, and the award is settled shortly after the end of the vesting period.

Compensation expense for our equity awards is calculated as the number of unit awards less forfeitures, multiplied by the grant date fair value of those awards, multiplied by the percentage of the requisite service period completed at each period end, multiplied by the expected payout percentage, less previously-recognized compensation expense.

Non-deferred director awards are paid in units valued on the grant date, with compensation expense calculated as the number of units awarded multiplied by the fair value of those units at that date. We classify deferred director awards as liability awards because they may be settled in cash. Because deferred director awards have distribution equivalent rights, the fair value of these awards equals the closing price of our units at the measurement date. Compensation expense for deferred director awards is calculated as the number of units awarded, multiplied by the fair value of those awards on the measurement date, less previously-recognized compensation expense. Director awards deferred prior to 2015 are paid in January of the year following the director's resignation from the board of directors of our general partner or death. Director awards deferred after January 1, 2015 are paid 60 days following the director's death or resignation from the board of directors of our general partner.

Non-Vested Unit Awards

The following table includes the changes during the current fiscal year in the number of non-vested units that have been granted by the compensation committee. The amounts below do not include adjustments for above-target or below-target performance.

	Performance-Based Awards		Time-Based Awards		Total Awards	
	Number of Unit Awards	Weighted-Average Fair Value	Number of Unit Awards	Weighted-Average Fair Value	Number of Unit Awards	Weighted-Average Fair Value
Non-vested units - 1/1/2019	390,015	$ 77.66	111,388	$ 73.09	501,403	$ 76.65
Units granted during 2019	182,834	$ 63.65	195,031	$ 62.91	377,865	$ 63.27
Units vested during 2019	(173,842)	$ 82.31	(30,958)	$ 78.05	(204,800)	$ 81.67
Units forfeited during 2019	(19,103)	$ 70.69	(15,145)	$ 65.18	(34,248)	$ 68.25
Non-vested units - 12/31/19	379,904	$ 69.14	260,316	$ 63.92	640,220	$ 67.02

The table below summarizes the total non-vested unit awards outstanding adjusted for estimated amounts of above-target financial performance to determine the total number of unit awards included in our total equity-based liability accrual.

Grant Date	Non-Vested Unit Awards	Adjustment to Unit Awards in Anticipation of Achieving Above-Target Financial Results	Total Unit Award Accrual	Vesting Date	Unrecognized Compensation Expense(a) (in millions)
Performance-Based Awards:					
2018 Awards	205,568	—	205,568	12/31/2020	$ 4.9
2019 Awards	174,336	—	174,336	12/31/2021	7.3
Time-Based Awards:					
2020 Vesting Date	76,820	—	76,820	12/31/2020	1.9
2021 Vesting Date	180,162	—	180,162	12/31/2021	7.5
2022 Vesting Date	3,334	—	3,334	12/31/2022	0.2
Total	640,220	—	640,220		$ 21.8

(a) Unrecognized compensation expense will be recognized over the remaining vesting period of the awards.

Weighted-Average Fair Value

The weighted-average fair value of awards granted during 2017, 2018 and 2019 was as follows:

	Performance-Based Awards			Time-Based Awards		
	Number of Unit Awards	Weighted-Average Fair Value		Number of Unit Awards	Weighted-Average Fair Value	
Units granted during 2017	189,544	$	82.34	30,604	$	79.10
Units granted during 2018	218,923	$	73.80	83,564	$	71.03
Units granted during 2019	182,834	$	63.65	195,031	$	62.91

Vested Unit Awards

The table below sets forth the numbers and values of units that vested in each of the three years ended December 31, 2019. The vested common units include adjustments for above-target financial and market performance.

Vesting Date	Vested Common Units	Fair Value of Unit Awards on Vesting Date (in millions)	Intrinsic Value of Unit Awards on Vesting Date (in millions)
12/31/2017	266,028	$19.9	$18.9
12/31/2018	317,037	$22.1	$18.1
12/31/2019	436,629	$31.0	$27.5

Cash Flow Effects of LTIP Settlements

The difference between the common units issued to the participants and the total number of unit awards vested primarily represents the tax withholdings associated with the award settlement, which we pay in cash.

Settlement Date	Number of Common Units Issued, Net of Tax Withholdings	Tax Withholdings and Other Cash Payments (in millions)	Employer Taxes (in millions)	Total Cash Payments (in millions)
January 2017	216,679	$13.9	$1.2	$15.1
January 2018	168,913	$9.3	$1.1	$10.4
January 2019	199,792	$9.8	$0.9	$10.7

Compensation Expense Summary

Equity-based incentive compensation expense for 2017, 2018 and 2019, primarily recorded as G&A expense on our consolidated statements of income, was as follows (in thousands):

	Year Ended December 31,		
	2017	2018	2019
Performance awards	$ 17,823	$ 28,728	$ 17,920
Time-based awards	2,818	3,325	6,092
Total	$ 20,641	$ 32,053	$ 24,012

13. Derivative Financial Instruments

We use derivative instruments to manage market price risks associated with inventories, interest rates and certain forecasted transactions. For those instruments that qualify for hedge accounting, the accounting treatment depends on their intended use and their designation. We divide derivative financial instruments qualifying for hedge accounting treatment into two categories: (1) cash flow hedges and (2) fair value hedges. We execute cash flow hedges to hedge against the variability in cash flows related to a forecasted transaction and execute fair value hedges to hedge against the changes in the value of a recognized asset or liability. At the inception of a hedged transaction, we document the relationship between the hedging instrument and the hedged item, the risk management objectives and the methods used for assessing and testing hedge effectiveness. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or fair value of the hedged item. If we determine that a derivative originally designated as a cash flow or fair value hedge is no longer highly effective, we discontinue hedge accounting prospectively and record the change in the fair value of the derivative in current earnings. The changes in fair value of derivative financial instruments that are not designated as hedges for accounting purposes, which we refer to as economic hedges, are included in current earnings.

As part of our risk management process, we assess the creditworthiness of the financial and other institutions with which we execute financial derivatives. Such financial instruments involve the risk of non-performance by the counterparty, which could result in material losses to us.

Our policies prohibit us from engaging in speculative trading activities.

Interest Rate Derivatives

We periodically enter into interest rate derivatives to hedge the fair value of debt or hedge against variability in interest rates. For interest rate cash flow hedges, we record the unrealized gains or losses as an adjustment to other comprehensive income. The realized gains and losses from our cash flow hedges are recognized into earnings as an adjustment to our periodic interest expense over the life of the related debt issuance. For fair value hedges on long-term debt, we record the unrealized gains or losses as an adjustment to long-term debt, and realized amounts as an adjustment to our periodic interest expense. Adjustments resulting from discontinued hedges continue to be recognized in accordance with their historic hedging relationships.

In 2019, upon issuance of our $500.0 million of 3.95% notes due 2050, we terminated and settled treasury lock agreements we had previously entered into to protect against the variability of interest payments on this anticipated debt issuance for a loss of $25.3 million, which was included in our statements of cash flows as a net payment on financial derivatives. These agreements were accounted for as cash flow hedges. The loss was recorded to other comprehensive income (loss) and will be recognized into earnings as an adjustment to our periodic interest expense over the life of the associated notes.

In 2019, upon issuance of $500.0 million of 4.85% notes due 2049, we terminated and settled treasury lock agreements that we had previously entered into to protect against the variability of interest payments on this anticipated debt issuance for a loss of $8.0 million, which was included in our statements of cash flows as a net payment on financial derivatives. These agreements were accounted for as cash flow hedges. The loss was recorded to other comprehensive income (loss) and will be recognized into earnings as an adjustment to our periodic interest expense over the life of the associated notes.

During 2018, we terminated and settled $200.0 million of interest rate derivative agreements with cumulative gains of $24.6 million. These agreements were previously entered into to protect against the risk of variability of interest payments on debt we issued in 2019. These agreements were accounted for as cash flow hedges. The gains were recorded to other comprehensive income (loss) and will be recognized into earnings as an adjustment to our periodic interest expense over the life of the associated notes. These gains were also reported as a net receipt on financial derivatives in the financing activities of our consolidated statements of cash flows in 2018.

Commodity Derivatives

Our gas liquids blending activities produce gasoline, and we can reasonably estimate the timing and quantities of sales of these products. We use a combination of exchange-based commodities futures contracts and forward purchase and sale contracts to help manage commodity price changes and mitigate the risk of decline in the product margin realized from our gas liquids blending activities. Further, certain of our other commercial operations generate petroleum products, and we also use futures contracts to hedge against price changes for some of these commodities.

Forward physical purchase and sale contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting, whereby changes in the mark-to-market values of such contracts are not recognized in income, rather the revenues and expenses associated with such transactions are recognized during the period when commodities are physically delivered or received. Physical forward commodity contracts subject to this exception are evaluated for the probability of future delivery and are periodically tested once the forecasted period has passed to determine whether similar forward contracts are probable of physical delivery in the future.

We record the effective portion of the gains or losses for commodity-based contracts designated as fair value hedges as adjustments to the assets being hedged and the ineffective portions as well as amounts excluded from the assessment of hedge effectiveness as adjustments to other income or expense. We recognize the change in fair value of economic hedges that hedge against changes in the price of petroleum products that we expect to sell or purchase in the future currently in earnings as adjustments to product sales revenue, cost of product sales, or operating expenses, as applicable.

Our open futures contracts at December 31, 2019 were as follows:

Type of Contract/Accounting Methodology	Product Represented by the Contract and Associated Barrels	Maturity Dates
Futures - Economic Hedges	3.2 million barrels of refined products and crude oil	Between January and May 2020
Futures - Economic Hedges	0.7 million barrels of gas liquids	Between January and April 2020

Commodity Derivatives Contracts and Deposits Offsets

At December 31, 2019, we had made margin deposits of $27.4 million for our futures contracts with our counterparties, which were recorded as current assets under commodity derivatives deposits on our consolidated balance sheets. At December 31, 2018, we held margin deposits of $37.3 million for our futures contracts with our counterparties, which were recorded as a current liabilities under commodity derivatives deposits on our consolidated balance sheets. We have the right to offset the combined fair values of our open futures contracts against our margin deposits under a master netting arrangement for each counterparty; however, we have elected to present the combined fair values of our open futures contracts separately from the related margin deposits on our consolidated balance sheets. Additionally, we have the right to offset the fair values of our futures contracts together for each counterparty, which we have elected to do, and we report the combined net balances on our consolidated balance sheets. A schedule of the derivative amounts we have offset and the deposit amounts we could offset under a master netting arrangement are provided below as of December 31, 2018 and 2019 (in thousands):

	Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts of Assets (Liabilities) Offset in the Consolidated Balance Sheets	Net Amounts of Assets (Liabilities) Presented in the Consolidated Balance Sheets	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheets	Net Asset Amount[(1)]
As of December 31, 2018	$ 62,166	$ (7,155)	$ 55,011	$ (37,328)	$ 17,683
As of December 31, 2019	$ (11,033)	$ 811	$ (10,222)	$ 27,415	$ 17,193

(1) Amount represents the maximum loss we would incur if all of our counterparties failed to perform on their derivative contracts.

Basis Derivative Agreement

During 2019, we entered into a basis derivative agreement with a joint venture co-owner's affiliate, and, contemporaneously, that affiliate entered into an intrastate transportation services agreement with the joint venture. Settlements under the basis derivative agreement are determined based on the basis differential of crude oil prices at different market locations and a notional volume of 30,000 barrels per day. As a result, we account for this agreement as a derivative. The agreement will expire in early 2022. We recognize the changes in fair value of this agreement based on forward price curves for crude oil in West Texas and the Houston Gulf Coast in other operating income (expense) in our consolidated statements of income. The liability for this agreement at December 31, 2019 was $17.3 million.

Impact of Derivatives on Our Financial Statements

Comprehensive Income

The changes in derivative activity included in AOCL for the years ended December 31, 2017, 2018 and 2019 were as follows (in thousands):

	Year Ended December 31,		
Derivative Gains (Losses) Included in AOCL	**2017**	**2018**	**2019**
Beginning balance	$ (34,776)	$ (33,755)	$ (26,480)
Net gain (loss) on interest rate contract cash flow hedges	(1,937)	4,317	(25,216)
Reclassification of net loss on cash flow hedges to income	2,958	2,958	2,736
Ending balance	$ (33,755)	$ (26,480)	$ (48,960)

The following is a summary of the effect on our consolidated statements of income for the years ended December 31, 2017, 2018 and 2019 of derivatives that were designated as cash flow hedges (in thousands):

	Interest Rate Contracts		
	Amount of Gain (Loss) Recognized in AOCL on Derivatives	Location of Loss Reclassified from AOCL into Income	Amount of Loss Reclassified from AOCL into Income
Year Ended December 31, 2017	$ (1,937)	Interest expense	$ (2,958)
Year Ended December 31, 2018	$ 4,317	Interest expense	$ (2,958)
Year Ended December 31, 2019	$ (25,216)	Interest expense	$ (2,736)

As of December 31, 2019, the net loss estimated to be classified to interest expense over the next twelve months from AOCL is approximately $3.2 million. This amount relates to the amortization of losses on interest rate contracts over the life of the related debt instruments.

The following table provides a summary of the effect on our consolidated statements of income for the years ended December 31, 2017, 2018 and 2019 of derivatives that were not designated as hedging instruments (in thousands):

		Amount of Gain (Loss) Recognized on Derivative		
		Year Ended December 31,		
Derivative Instrument	Location of Gain (Loss) Recognized on Derivatives	2017	2018	2019
Futures contracts	Product sales revenue	$ (56,338)	$ 85,012	$ (72,562)
Futures contracts	Cost of product sales	25,566	(15,947)	(1,931)
Futures contracts	Operating expenses	3,002	—	—
Basis derivative agreement	Other operating income (expense)	—	—	(10,252)
	Total	$ (27,770)	$ 69,065	$ (84,745)

The impact of the derivatives in the above table was reflected as cash from operations on our consolidated statements of cash flows.

Balance Sheets

The following table provides a summary of the fair value of derivatives, which are presented on a net basis in our consolidated balance sheets, that were designated as hedging instruments as of December 31, 2018 (in thousands). There were no derivatives designated as hedging instruments as of December 31, 2019.

	December 31, 2018			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Commodity derivatives contracts, net	$ 462	Commodity derivatives contracts, net	$ —
Interest rate contracts	Other noncurrent assets	312	Other noncurrent liabilities	8,438
	Total	$ 774	Total	$ 8,438

The following tables provide a summary of the fair value of derivatives, which are presented on a net basis in our consolidated balance sheets, that were not designated as hedging instruments as of December 31, 2018 and 2019 (in thousands):

	December 31, 2018			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Commodity derivatives contracts, net	$ 61,704	Commodity derivatives contracts, net	$ 7,155

	December 31, 2019			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Commodity derivatives contracts, net	$ 811	Commodity derivatives contracts, net	$ 11,033
Basis derivative agreement	Other current assets	—	Other current liabilities	8,457
Basis derivative agreement	Other noncurrent assets	—	Other noncurrent liabilities	8,847
	Total	$ 811	Total	$ 28,337

14. Fair Value Disclosures

Fair Value Methods and Assumptions - Financial Assets and Liabilities

The following methods and assumptions were used in estimating fair value for our financial assets and liabilities:

- *Commodity derivatives contracts*. These include exchange-traded futures contracts related to petroleum products. These contracts are carried at fair value on our consolidated balance sheets and are valued based on quoted prices in active markets. See Note 13 – *Derivative Financial Instruments* for further disclosures regarding these contracts.

- *Interest rate contracts.* These include forward-starting interest rate swap agreements to hedge against the risk of variability of interest payments on future debt. These contracts are carried at fair value on our consolidated balance sheets and are valued based on an assumed exchange, at the end of each period, in an orderly transaction with a participant in the market in which the financial instrument is traded. The exchange value was calculated using present value techniques on estimated future cash flows based on forward interest rate curves. See Note 13 – *Derivative Financial Instruments* for further disclosures regarding these contracts.

- *Basis Derivative Agreement.* During 2019, we entered into a basis derivative agreement with a joint venture co-owner's affiliate, and, contemporaneously, that affiliate entered into an intrastate transportation services agreement with the joint venture. Settlements under the basis derivative agreement are determined based on the basis differential of crude oil prices at different market locations and a notional volume of 30,000 barrels per day (see Note 13 - *Derivative Financial Instruments* for further disclosures regarding this agreement). The fair value of this derivative was calculated based on observable market data inputs, including published commodity pricing data and market interest rates. The key inputs in the fair value calculation include the forward price curves for crude oil, the implied forward correlation in crude oil prices between West Texas and the Houston Gulf Coast, and the implied forward volatility for crude oil futures contracts.

- *Long-term receivables.* These primarily include payments receivable under a sales-type leasing arrangement and cost reimbursement payments receivable. These receivables were recorded at fair value on our consolidated balance sheets, using then-current market rates to estimate the present value of future cash flows.

- *Guarantees.* At December 31, 2018, these guarantees primarily included an indemnification agreement we entered into in connection with the partial sale of our interest in BridgeTex. This indemnification was recorded at fair value on our consolidated balance sheets upon initial recognition, using probability-weighted potential outcome scenarios to estimate our possible liability for specific events covered by this indemnification. In first quarter 2019, certain litigation subject to the indemnification agreement was settled, which resulted in our paying $5.0 million under the indemnification agreement and recognizing the reduction of the remaining $11.0 million liability as an additional gain on disposition of assets on our consolidated statements of income.

- *Debt.* The fair value of our publicly traded notes was based on the prices of those notes at December 31, 2018 and 2019; however, where recent observable market trades were not available, prices were determined using adjustments to the last traded value for that debt issuance or by adjustments to the prices of similar debt instruments of peer entities that are actively traded. The carrying amount of borrowings, if any, under our revolving credit facility and our commercial paper program approximates fair value due to the frequent repricing of these obligations.

Fair Value Measurements - Financial Assets and Liabilities

The following tables summarize the carrying amounts, fair values and fair value measurements recorded or disclosed as of December 31, 2018 and 2019, based on the three levels established by ASC 820; *Fair Value Measurements and Disclosures* (in thousands):

			Fair Value Measurements as of December 31, 2018 using:		
Assets (Liabilities)	**Carrying Amount**	**Fair Value**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Commodity derivatives contracts	$ 55,011	$ 55,011	$ 55,011	$ —	$ —
Interest rate contracts	$ (8,126)	$ (8,126)	$ —	$ (8,126)	$ —
Long-term receivables	$ 20,844	$ 20,844	$ —	$ —	$ 20,844
Guarantees	$ (16,409)	$ (16,409)	$ —	$ —	$ (16,409)
Debt	$ (4,270,869)	$ (4,224,373)	$ —	$ (4,224,373)	$ —

			Fair Value Measurements as of December 31, 2019 using:		
Assets (Liabilities)	Carrying Amount	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity derivatives contracts	$ (10,222)	$ (10,222)	$ (10,222)	$ —	$ —
Basis derivative agreement	$ (17,304)	$ (17,304)	$ —	$ (17,304)	$ —
Long-term receivables	$ 20,782	$ 20,782	$ —	$ —	$ 20,782
Guarantees	$ (408)	$ (408)	$ —	$ —	$ (408)
Debt	$ (4,706,075)	$ (5,192,685)	$ —	$ (5,192,685)	$ —

15. Commitments and Contingencies

Certain conditions may exist as of the date our consolidated financial statements are issued that could result in a loss to us, but which will only be resolved when one or more future events occur or fail to occur. Our management assesses such contingent liabilities, which inherently involves significant judgment. In assessing loss contingencies related to legal proceedings that are pending against us or for unasserted claims that may result in proceedings, our management, with input from legal counsel, evaluates 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.

Environmental expenditures are charged to operating expense or capitalized based on the nature of the expenditures. Environmental expenditures that meet the capitalization criteria for property, plant and equipment, as well as costs that mitigate or prevent environmental contamination that has yet to occur, are capitalized. We expense expenditures that relate to an existing condition caused by past operations. We initially record environmental liabilities assumed in a business combination at fair value; otherwise, we record environmental liabilities on an undiscounted basis. We recognize liabilities for other commitments and contingencies when, after analyzing the available information, we determine it is probable that an asset has been impaired, or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When we can estimate a range of probable loss, we accrue the most likely amount within that range, or if no amount is more likely than another, we accrue the minimum of the range of probable loss. We expense legal costs associated with loss contingencies as incurred.

We record environmental liabilities independently of any potential claim for recovery. Accruals related to environmental matters are generally determined based on site-specific plans for remediation, taking into account currently available facts, existing technologies and presently enacted laws and regulations. Accruals for environmental matters reflect our prior remediation experience and include an estimate for costs such as fees paid to contractors, outside engineering and consulting firms. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remediation feasibility study. Such accruals are adjusted as further information develops or circumstances change.

We maintain specific insurance coverage, which may cover all or portions of certain environmental expenditures less a deductible. We recognize receivables in cases where we consider the realization of reimbursements of remediation costs as probable. We would sustain losses to the extent of amounts we have recognized as environmental receivables if the counterparties to those transactions were unable to perform their obligations to us.

The determination of the accrual amounts recorded for environmental liabilities includes significant judgments and assumptions made by management. The use of alternate judgments and assumptions could result in the recognition of different levels of environmental remediation costs.

Butane Blending Patent Infringement Proceeding

On October 4, 2017, Sunoco Partners Marketing & Terminals L.P. ("Sunoco") brought an action for patent infringement in the U.S. District Court for the District of Delaware alleging Magellan Midstream Partners, L.P. ("Magellan") and Powder Springs Logistics, LLC ("Powder Springs") have infringed patents relating to butane blending at the Powder Springs facility located in Powder Springs, Georgia. Sunoco has since submitted pleadings alleging that Magellan has also infringed various patents relating to butane blending at nine Magellan facilities, in addition to Powder Springs. Sunoco is seeking monetary damages, attorneys' fees and a permanent injunction enjoining Magellan and Powder Springs from infringing the subject patents. We deny and are vigorously defending against all claims asserted by Sunoco. Although it is not possible to predict the ultimate outcome, we believe the ultimate resolution of this matter will not have a material adverse impact on our results of operations, financial position or cash flows.

Environmental Liabilities

Liabilities recognized for estimated environmental costs were $20.5 million and $14.9 million at December 31, 2018 and December 31, 2019, respectively. We have classified environmental liabilities as other current or noncurrent based on management's estimates regarding the timing of actual payments. Environmental expenses recognized as a result of changes in our environmental liabilities are included in operating expenses on our consolidated statements of income. Environmental expenses were $9.0 million, $15.0 million and $4.4 million for the years ended December 31, 2017, 2018 and 2019, respectively.

Environmental Receivables

Receivables from insurance carriers and other third parties related to environmental matters at December 31, 2018 were $4.1 million, of which $2.4 million and $1.7 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheets. Receivables from insurance carriers related to environmental matters at December 31, 2019 were $2.9 million, of which $1.8 million and $1.1 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheets. Amounts received from insurance carriers and other third parties related to environmental matters during 2017, 2018 and 2019 were $0.7 million, $3.1 million and $1.4 million, respectively.

Other

We have entered into an agreement to guarantee our 50% pro rata share, up to $25.0 million, of obligations under Powder Springs' credit facility. As of December 31, 2019, our consolidated balance sheets reflected a $0.4 million other current liability and a corresponding increase in our investment in non-controlled entities on our consolidated balance sheets to reflect the fair value of this guarantee.

We and the non-controlled entities in which we own an interest are a party to various other claims, legal actions and complaints, including without limitation those disclosed in Item 3. *Legal Proceedings* of Part I of our annual report on Form 10-K. While the results cannot be predicted with certainty, management believes the ultimate resolution of these claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification arrangements will not have a material adverse effect on our results of operations, financial position or cash flows.

16. Major Customers and Concentration of Risks

Major Customers. No customer accounted for more than 10% of our consolidated revenues during 2017, 2018 or 2019.

Concentration of Risks. We transport, store and distribute petroleum products for refiners, producers, marketers, traders and end users of those products. Our revenue producing activities are concentrated in the central U.S. Concentrations of customers may affect our overall credit risk as our customers may be similarly affected by changes in economic, regulatory or other factors. We generally secure transportation and storage revenue with warehouseman's liens. We periodically evaluate the financial condition and creditworthiness of our customers and require additional security as we deem necessary.

As of December 31, 2019, we had 1,884 employees, 1,088 of which were assigned to our refined products segment and concentrated in the central U.S. Approximately 21% of our refined products segment employees were represented by the United Steel Workers and covered by a collective bargaining agreement that expires in January 2022. Approximately 3% of our refined products segment employees were represented by the International Union of Operating Engineers ("IUOE") and covered by a collective bargaining agreement that expires in October 2020. All of the IUOE employees are located at the New Haven terminal, which we sold in first quarter of 2020. There were 224 employees assigned to our crude oil segment and concentrated in the central U.S., and none of these employees were covered by a collective bargaining agreement.

17. Related Party Transactions

Stacy P. Methvin is an independent member of our general partner's board of directors and is also a director of one of our customers. We received tariff, terminalling and other ancillary revenue from this customer of $16.6 million, $21.7 million and $29.6 million for the periods ending December 31, 2017, 2018 and 2019, respectively. We recorded a receivable of $1.9 million and $3.8 million from this customer at December 31, 2018 and 2019, respectively. We also made a one-time payment of $0.2 million in 2019 to a subsidiary of this customer for an easement related to one of our expansion projects.

See Note 6 – *Investments in Non-Controlled Entities* for a discussion of transactions with our joint venture affiliates.

18. Partners' Capital and Distributions

Partners' Capital

The following table details the changes in the number of our common units outstanding from January 1, 2017 through December 31, 2019:

Common units outstanding on January 1, 2017	**227,783,916**
January 2017—Settlement of employee LTIP awards	216,679
During 2017—Other[(a)]	23,961
Common units outstanding on December 31, 2017	**228,024,556**
January 2018—Settlement of employee LTIP awards	168,913
During 2018—Other[(a)]	1,691
Common units outstanding on December 31, 2018	**228,195,160**
February 2019—Settlement of employee LTIP awards	199,792
During 2019—Other(a)	8,476
Common units outstanding on December 31, 2019	**228,403,428**

(a) Common units issued to settle the equity-based retainer paid to independent directors of our general partner.

Our partnership agreement allows us to issue additional partnership securities for any partnership purpose at any time and from time to time for consideration and on terms and conditions as our general partner determines, all without approval by our unitholders.

Common unitholders have the following rights, among others:

- right to receive distributions of our available cash within 45 days after the end of each quarter;
- right to elect the board members of our general partner;
- right to remove Magellan GP, LLC as our general partner upon a 100% vote of outstanding unitholders;
- right to transfer common unit ownership to substitute common unitholders;
- right to receive an annual report, containing audited financial statements and a report on those financial statements by our independent public accountants, within 120 days after the close of the fiscal year end;
- right to receive information reasonably required for tax reporting purposes within 90 days after the close of the calendar year;
- right to vote according to the unitholder's percentage interest in us at any meeting that may be called by our general partner; and
- right to inspect our books and records at the unitholder's own expense.

In the event of liquidation, we would distribute all property and cash in excess of that required to discharge all liabilities to the unitholders in proportion to the positive balances in their respective capital accounts. The common unitholders' liability is generally limited to their investment.

Distributions

Distributions we paid during 2017, 2018 and 2019 were as follows (in thousands, except per unit amount):

Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution
2/14/2017	$ 0.8550	$ 194,961
5/15/2017	0.8725	198,951
8/14/2017	0.8900	202,942
11/14/2017	0.9050	206,362
Total	$ 3.5225	$ 803,216
2/14/2018	$ 0.9200	$ 209,940
5/15/2018	0.9375	213,933
8/14/2018	0.9575	218,497
11/14/2018	0.9775	223,061
Total	$ 3.7925	$ 865,431
2/14/2019	$ 0.9975	$ 227,832
5/15/2019	1.0050	229,545
8/14/2019	1.0125	231,258
11/14/2019	1.0200	232,971
Total	$ 4.0350	$ 921,606

19. Subsequent Events

Recognizable events

No recognizable events have occurred subsequent to December 31, 2019.

Non-recognizable events

The recent period of unprecedented restrictions on travel and economic activity has significantly reduced demand for refined products in the markets we serve. Recent declines in commodity prices have also significantly reduced the value of tender barrels we receive from our transportation customers and the margins we earn from our gas liquids blending activities. The reduction in refined products demand, lower crude oil prices and limited storage capacity for petroleum products have combined to put significant downward pressure on domestic crude oil production. While we benefit from take-or-pay commitments for the majority of the capacity of our crude oil pipelines, a sustained reduction in crude oil production could cause delays in the timing of our recognition of revenue from these commitments. These factors have also significantly decreased the creditworthiness of certain of our crude oil transportation customers, resulting in an increased risk of customer defaults. To date, our operations and our employees have successfully adapted to the recent developments, enabling our customers to continue benefiting from the services they rely on from our critical infrastructure, and our customers have continued to meet their obligations to us. Given the uncertain timing of a return of refined product demand to historical levels and of a recovery in commodity prices, the extent of the impact these events will have on our results of operations is unclear, but will likely be material. However, we do not believe these events will impact our ability to meet any of our financial obligations or result in any significant impairments to our assets.

In April 2020, our general partner's board of directors declared a quarterly cash distribution of $1.0275 per unit for the period of January 1, 2020 through March 31, 2020. This quarterly cash distribution will be paid on May 15, 2020 to unitholders of record on May 8, 2020.

In March 2020, we sold three marine terminals to a subsidiary of Buckeye Partners, L.P. for $252.6 million. The terminals are located in New Haven, Connecticut, Wilmington, Delaware and Marrero, Louisiana. We recognized a $5.4 million impairment loss related to the sale on our consolidated statements of income in first quarter 2020.

In February 2020, we sold a 10% interest in Saddlehorn to an affiliate of Black Diamond Gathering LLC, which is majority-owned by Noble Midstream Partners LP, reducing our ongoing investment in Saddlehorn to a 30% interest. We received $79.9 million in cash from the sale, and we recorded a gain of $12.9 million on our consolidated statements of income in first quarter 2020.

On February 14, 2020, we paid cash distributions of $1.0275 per unit on our outstanding common units to unitholders of record at the close of business on February 7, 2020.

On January 21, 2020, we announced that our general partner's board of directors authorized the repurchase of up to $750 million of common units through 2022. During the three months ended March 31, 2020, we repurchased approximately 3.6 million of our common units for $202 million. The timing, price and actual number of common units repurchased will depend on a number of factors including our expected expansion capital spending needs, alternative investment opportunities, excess cash available, legal and regulatory requirements, market conditions and the trading price of our common units. The repurchase program does not obligate us to acquire any particular amount of common units, and the repurchase program may be suspended or discontinued at any time.

Quarterly Financial Data (unaudited)

Summarized quarterly financial data is as follows (in thousands, except per unit amounts):

2018	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$ 678,779	$ 644,091	$ 638,020	$ 865,683
Total costs and expenses	$ 441,323	$ 420,433	$ 396,242	$ 555,111
Operating margin	$ 370,429	$ 373,077	$ 399,190	$ 511,245
Net income	$ 210,910	$ 214,409	$ 594,534	$ 314,072
Basic net income per common unit	$ 0.92	$ 0.94	$ 2.60	$ 1.38
Diluted net income per common unit	$ 0.92	$ 0.94	$ 2.60	$ 1.37
2019				
Revenue	$ 628,935	$ 701,699	$ 656,596	$ 740,682
Total costs and expenses	$ 422,985	$ 436,718	$ 385,927	$ 450,514
Operating margin	$ 352,012	$ 415,655	$ 428,262	$ 450,559
Net income	$ 207,663	$ 253,703	$ 273,038	$ 286,445
Basic net income per common unit	$ 0.91	$ 1.11	$ 1.19	$ 1.25
Diluted net income per common unit	$ 0.91	$ 1.11	$ 1.19	$ 1.25

In fourth quarter 2018, we made the decision to discontinue commercial operations of our ammonia pipeline due to the system's low profitability and challenging economic outlook. As a result, we recognized a $49.1 million impairment charge, which impacted total costs and expenses and net income on our consolidated statements of income.

In third quarter 2018, we sold a 20% interest in BridgeTex to an affiliate of OMERS Infrastructure Management Inc., which reduced our ongoing ownership in BridgeTex to a 30% interest. We received $575.6 million in cash from the sale and recognized a gain of $353.8 million that impacted net income on our consolidated statements of income.