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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2016

or

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

Commission file number 1-16335

Magellan Midstream Partners, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**73-1599053**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
Magellan GP, LLC **P.O. Box 22186, Tulsa, Oklahoma**	**74121-2186**
(Address of principal executive offices)	**(Zip Code)**

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Units representing limited partnership interests	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the registrant's voting and non-voting limited partner units held by non-affiliates computed by reference to the price at which the limited partner units were last sold as of June 30, 2016 was $17,271,907,668.

As of February 16, 2017, there were 228,024,556 limited partner units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement prepared for the solicitation of proxies in connection with the 2017 Annual Meeting of Limited Partners are to be incorporated by reference in Part III of this Form 10-K.

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MAGELLAN MIDSTREAM PARTNERS, L.P.

FORM 10-K

PART I

Item 1. ***Business***

(a) General Development of Business

We are a Delaware limited partnership formed in August 2000 and our limited partner 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 our general partner. Unless indicated otherwise, the terms "our," "we," "us" and similar language refer to Magellan Midstream Partners, L.P. together with its subsidiaries.

(b) Financial Information About Segments

See Part II—Item 8. Financial Statements and Supplementary Data, Note 16 – *Segment Disclosures*.

(c) Narrative Description of Business

We are principally engaged in the transportation, storage and distribution of refined petroleum products and crude oil. As of December 31, 2016, our asset portfolio, including the assets of our joint ventures, consisted of:

- our refined products segment, comprised of our 9,700-mile refined products pipeline system with 53 terminals as well as 26 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

- our crude oil segment, comprised of approximately 2,200 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 26 million barrels, of which 16 million are used for contract storage; and

- our marine storage segment, consisting of five marine terminals located along coastal waterways with an aggregate storage capacity of approximately 26 million barrels.

Industry Background

The 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 and distribute through our pipelines and terminals:

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

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

- *blendstocks* are 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 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 and condensate* are used as feedstocks by refineries and petrochemical facilities;

- *biofuels,* such as ethanol and biodiesel, are typically blended with other refined products as required by government mandates; and

- *ammonia* is primarily used as a nitrogen fertilizer.

Except for ammonia, 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 common carrier refined products pipeline system, independent terminals and our ammonia pipeline system. Our refined products pipeline system is the longest common carrier pipeline system for refined products and LPGs in the U.S., extending approximately 9,700 miles from the Gulf Coast and covering a 15-state area across the central U.S. The system includes approximately 42 million barrels of aggregate usable storage capacity at 53 connected terminals. Our network of independent terminals includes 26 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 1,100-mile common carrier ammonia pipeline system extends from production facilities in Texas and Oklahoma to terminals in agricultural demand centers in the Midwest.

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

	Year Ended December 31,		
	2014	**2015**	**2016**
Percent of consolidated revenue	77%	73%	71%
Percent of consolidated operating margin	68%	61%	57%
Percent of consolidated total assets	52%	50%	49%

See Note 16—*Segment Disclosures* in the accompanying consolidated financial statements in Item 8 for additional financial information about our refined products segment.

Operations. *Transportation, Terminalling and Ancillary Services.* During 2016, approximately 70% 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 Federal Energy Regulatory Commission ("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.

In 2016, the products transported on our refined products pipeline system were comprised of 60% gasoline, 32% distillates and 8% aviation fuel and LPGs. The operating statistics below reflect our refined products pipeline system's operations for the periods indicated:

	Year Ended December 31,		
	2014	2015	2016
Shipments (million barrels):			
Gasoline	256.1	268.1	275.4
Distillates	163.1	152.5	150.2
Aviation fuel	23.0	21.2	25.7
LPGs	9.9	9.7	10.4
Total shipments	452.1	451.5	461.7

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. Furthermore, under our tariffs, we are allowed to deduct prescribed quantities of the products our shippers transport, which are commonly referred to as "tender deductions," on our pipelines 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 losses 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 losses we incur during the shipment process.

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 ammonia pipeline system generates revenue primarily through transportation tariffs on volumes shipped.

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

Our butane 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. We typically hedge the economic margin from this blending activity by entering into either forward physical or exchange-traded gasoline futures contracts at the time we purchase the related butane. These blending activities accounted for approximately 71% of the total product margin for the refined products segment during 2016. When the differential between the cost of butane and the price of gasoline is narrow, the product margin we earn from these activities is negatively impacted.

We also operate three fractionators along our pipeline system that separate transmix, which is an unusable mixture of various refined products, into its original components. 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 separated refined products.

Product margin from commodity-related activities in our refined products segment was $279.7 million, $180.5 million and $101.8 million for the years ended December 31, 2014, 2015 and 2016, respectively. The amount of margin we earn from these activities fluctuates with changes in petroleum prices. Product margin is not a generally accepted accounting principle ("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, is provided in Note 16—*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 develop a butane blending system, including 120,000 barrels of butane storage, near Atlanta, Georgia. We served as construction manager and serve as operator of the Powder Springs facility, which we expect to begin operating in first quarter 2017.

Markets and Competition. Shipments originate on our refined products pipeline system from direct connections to refineries, through interconnections with other interstate pipelines or at our 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 48% of U.S. refining capacity, and in particular is well-connected to Gulf Coast and Mid-Continent refineries. Our system is dependent on the ability of refiners and marketers to meet the demand for those products in the markets they serve through their shipments on our pipeline system. According to September 2016 projections provided by the Energy Information Administration, which represent the latest long-term outlook at this point, the demand for refined products in the primary market areas served by our pipeline system, known as the West North Central and West South Central census districts, is expected to remain relatively stable over the next 10 years. 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.

In 2016, approximately 70% of the products transported on our refined products pipeline system originated from 19 direct refinery connections and 30% originated from connections with other pipelines or terminals.

As set forth in the table below, our system is directly connected to and receives product from the following 19 refineries:

Major Origins—Refineries (Listed Alphabetically)

Company	Refinery Location
Calumet Specialty Products	Superior, WI
CHS	McPherson, KS
CVR Energy	Coffeyville, KS
CVR Energy	Wynnewood, OK
Flint Hills Resources	Rosemount, MN
HollyFrontier	El Dorado, KS
HollyFrontier	Tulsa, OK
HollyFrontier	Cheyenne, WY
Marathon	Galveston Bay, TX
Marathon	Texas City, TX
Phillips 66	Ponca City, OK
Sinclair	Evansville, WY
Suncor Energy	Commerce City, CO
Valero	Ardmore, OK
Valero	Houston, TX
Valero	Texas City, TX
Western Refining	St. Paul, MN
Western Refining	El Paso, TX
Wyoming Refining	Newcastle, WY

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

Major Origins—Pipeline and Terminal Connections (Listed Alphabetically)

Pipeline/Terminal	Connection Location	Source of Product
BP	Manhattan, IL	Whiting, IN refinery
CHS	Fargo, ND	Laurel, MT refinery
Explorer	Glenpool, OK; Mt. Vernon, MO; Dallas, TX; East Houston, 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 Terminals Holdings	Galena Park, TX	Various Gulf Coast refineries and imports
Mid-America (Enterprise)	El Dorado, KS	Conway, KS storage
NuStar Energy	El Dorado, KS; Minneapolis, MN; Denver, CO	Various OK & KS refineries, Mandan, ND refinery, McKee, TX refinery
ONEOK Partners	Plattsburg, MO; Des Moines, IA; Wayne, IL	Bushton, KS storage and Chicago, IL area refineries
Phillips 66	Kansas City, KS; Denver, CO; Casper, WY; Pasadena, TX	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, pricing at either the origin or terminal 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 shipper agrees to supply a market near its refinery or terminal in exchange for receiving supply from another refinery or terminal in a more distant market. These agreements allow the two parties to reduce the volumes transported and 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, most of 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 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 ammonia pipeline system receives product from ammonia production facilities in Texas and Oklahoma and delivers to agricultural markets in the Midwest, where the ammonia is used by farmers as a nitrogen fertilizer. Our system competes primarily with ammonia shipped by rail carriers and in certain markets with a third-party ammonia pipeline.

Customers and Contracts. Our refined products pipeline system ships products for several different types of customers, including independent and integrated oil companies, wholesalers, retailers, traders, railroads, airlines, bio-fuel producers and regional farm cooperatives. End markets for refined products deliveries are primarily retail gasoline stations, truck stops, farm cooperatives, railroad fueling depots and military and commercial jet fuel users. LPG shippers include wholesalers and retailers that, in turn, sell to commercial, industrial, agricultural and residential heating customers, as well as utilities who use propane as a fuel source. 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 capital expansion commitments on our part. For 2016, approximately 37% of the shipments on our pipeline system were subject to these supplemental agreements. The average remaining life of these agreements was approximately four years as of December 31, 2016, with remaining terms of up to 12 years. 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, 2016, our refined products pipeline system had approximately 60 transportation customers. The top 10 shippers included independent refining companies, integrated oil companies and farm cooperatives. Revenue attributable to these top 10 shippers for the year ended December 31, 2016 represented 39% of total revenue for our refined products segment and 56% of revenue excluding product sales.

Customers of our independent terminals include independent and integrated oil companies, retailers, wholesalers and traders. Contracts vary in term and commitment and typically renew automatically at the end of each contract period.

Our ammonia pipeline system ships product for three customers who own production facilities connected to our system. We have agreements with these customers that contain minimum volume commitments whereby a customer must pay for unused pipeline capacity if the customer fails to ship its committed volume.

Product sales are primarily to trading and marketing or other 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 with an aggregate storage capacity of approximately 26 million barrels of storage, of which 16 million are used for contract storage. The crude oil segment includes: (i) the Longhorn pipeline; (ii) our Cushing, Oklahoma storage terminal; (iii) the Houston-area crude oil distribution system; (iv) the crude oil components of our East Houston, Texas terminal; (v) the crude oil components of our Corpus Christi, Texas terminal, including our recently constructed condensate splitter; (vi) the Gibson, Louisiana terminal; and (vii) the assets owned by our 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”) joint ventures.

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

	Year Ended December 31,		
	2014	2015	2016
Percent of consolidated revenue	15%	19%	20%
Percent of consolidated operating margin	23%	30%	32%
Percent of consolidated total assets	35%	38%	39%

See Note 16–*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 paid by shippers on our crude oil pipelines and storage fees paid by our crude oil terminal customers. In addition, we earn revenue for ancillary services including throughput fees. We generally do not take title to the products we ship or store for our crude oil customers. We do own certain tank bottom assets at our crude oil terminal in Cushing, Oklahoma that are not sold in the normal course of business and are classified as long-term assets on our consolidated balance sheets. In addition, 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.

The approximately 450-mile Longhorn pipeline has the capacity to transport up to 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-area crude oil distribution system that terminates in Texas City, Texas.

Our East Houston terminal includes approximately seven million barrels of crude oil storage, with approximately four million barrels used for contract storage and three million barrels dedicated to the operation of the Longhorn and BridgeTex pipelines, which deliver crude oil to our East Houston terminal. (See discussion of our BridgeTex joint venture under *Joint Venture Activities* below.) Our East Houston terminal is also connected to our Houston-area crude oil distribution system and to third-party pipelines, including the Houston-to-Houma pipeline, and Argus’ West Texas Intermediate (“WTI”) Houston price assessment is based on trades at the terminal. We are building additional storage at this location to facilitate movements on our pipeline systems or for contract storage.

Our Houston-area crude oil 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 Texas City, Texas. In addition, it is directly connected to other third-party crude oil pipelines providing us access to crude oil from the Eagle Ford shale, the strategic crude oil trading hub in Cushing, Oklahoma and crude oil imports.

Our Cushing terminal consists of approximately 12 million barrels of crude oil storage, of which two million barrels are reserved for working inventory, leaving 10 million barrels 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, 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 are leased to third parties, and we earn revenue from these pipeline segments for capacity reserved even if not used by the customers.

Our Corpus Christi, Texas terminal includes approximately two million barrels of condensate storage, with a portion used for contract storage and a portion used in conjunction with our Double Eagle joint venture discussed below. These assets receive product primarily from trucks, barges and pipelines that connect to our terminal for further distribution to end users by pipeline or waterborne vessels. In addition, we recently constructed a 50,000 bpd condensate splitter with approximately one million barrels of related storage at our terminal in Corpus Christi. For additional information regarding the splitter, see *Item 7. Management's Discussion and Analysis – Recent Developments*.

Joint Venture Activities. We own a 50% interest in BridgeTex, a joint venture with an affiliate of Plains All American Pipeline, L.P. ("Plains"). BridgeTex owns an approximately 400-mile pipeline currently capable of transporting up to 300,000 bpd of Permian Basin crude oil from Colorado City, Texas to our East Houston terminal. We are in the process of adding a new BridgeTex origin at Bryan, Texas and increasing the capacity of BridgeTex to 400,000 bpd, both of which are expected to be operational in second quarter 2017. We receive management fees to operate BridgeTex, which we report as affiliate management fee revenue on our consolidated statements of income. We entered into a long-term lease agreement with BridgeTex to provide it with capacity on our Houston-area crude oil distribution system, and we receive capacity lease revenue from this agreement, which is included in transportation and terminals revenue on our consolidated statements of income.

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 shale formation 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 Double Eagle. In addition to equity earnings recognized from our investment, we receive throughput revenue from Double Eagle that is included in our transportation and terminals revenue on our consolidated statements of income.

We own a 50% interest in HoustonLink, a joint venture with an affiliate of TransCanada Corporation ("TransCanada"). HoustonLink owns and operates a crude oil pipeline connecting TransCanada's Houston tank terminal to our East Houston terminal. The HoustonLink pipeline became operational at the end of 2016.

We own a 40% interest in Saddlehorn, a joint venture with an affiliate of Plains (40% interest) and an affiliate of Anadarko Petroleum Corporation (20% interest). Saddlehorn owns an undivided joint interest in an approximately 600-mile pipeline, which delivers various grades of crude oil from the DJ Basin region of Colorado to existing storage facilities in Cushing, Oklahoma. Saddlehorn has the capacity to deliver up to 190,000 bpd of crude oil. We received construction management fees from Saddlehorn during 2015 and 2016 and began receiving operational management fees when commercial service began in September 2016, which we report as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in Seabrook, a joint venture with an affiliate of LBC Tank Terminals, LLC ("LBC"). Seabrook is currently in the final stages of constructing more than 700,000 barrels of crude oil storage located adjacent to LBC's existing terminal in Seabrook, Texas and a pipeline that will connect Seabrook's storage facilities to an existing third-party pipeline that will transport crude oil to a Houston-area refinery beginning in the second quarter of 2017. In December 2016, Seabrook announced it will construct an additional 1.7 million barrels of crude oil storage and will construct a new pipeline to connect its facility to our Houston-area crude oil distribution system, expected to be operational in mid-2018.

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. Permian Basin production may vary based on numerous factors including overall crude oil prices and changes in costs of production, while Gulf Coast refinery 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 refined 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, 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, crude quality and customer relationships.

Volumes on our Houston-area crude oil 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 and crude oil storage in the Houston area. Our Houston-area distribution facilities compete with other distribution facilities in the Houston area based primarily on tariff rates and connectivity to supply sources and demand centers.

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 shale formation 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 and customer service. 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. Demand for our condensate 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 primarily from the Eagle Ford shale formation in South Texas and overall product 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 from the DJ Basin for its supply and competes primarily with other pipelines and supply alternatives that are capable of transporting crude oil from the DJ Basin production area to Cushing. Competition is based primarily on tariff rates, connectivity and customer service. 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. 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 and destination. In addition, tariff rates can vary with the volume of spot barrel movements on our pipelines, which generally ship at higher rates than those charged to committed shippers. Based on generally accepted practices, we reserve 10% of the shipping capacity of our pipelines for spot shippers. Generally, we secure long-term commitments to support our long-haul crude oil pipeline assets. Specifically with regard to our Longhorn pipeline, the vast majority of the volumes shipped on that system are supported by take-or-pay customer agreements. For 2016, approximately 55% of the shipments on our wholly-owned crude oil pipelines were subject to such commitments. The average remaining life of these contracts was approximately two years as of December 31, 2016. As of December 31, 2016, approximately 85% 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, 2016. 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 which support our capital investments in these joint ventures.

MARINE STORAGE

We own and operate five marine storage terminals located along coastal waterways with approximately 26 million barrels of aggregate storage capacity, including approximately one million barrels of storage jointly owned through our Texas Frontera, LLC joint venture ("Texas Frontera"). Our marine terminals provide distribution, storage, blending, inventory management and additive injection services for refiners, marketers, traders and other end users of petroleum products.

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

	Year Ended December 31,		
	2014	2015	2016
Percent of consolidated revenue	8%	8%	9%
Percent of consolidated operating margin	9%	9%	10%
Percent of consolidated total assets	12%	11%	12%

See Note 16–*Segment Disclosures* in the accompanying consolidated financial statements in Item 8 for additional financial information about our marine storage segment.

Operations. Our marine storage terminals generate revenue primarily through providing long-term storage services for a variety of customers. Refiners and chemical companies typically use our storage terminals due to tankage constraints at their facilities or the specialized handling requirements of the stored product. We also provide storage services to marketers and traders that require access to significant storage capacity. Because the rates charged at these terminals are unregulated, the marketplace determines the prices we charge for our services. In general, we do not take title to the products that are stored in or distributed from our marine terminals.

Our Galena Park, Texas marine terminal is located along the Houston Ship Channel and is our largest marine facility with 13 million barrels of wholly-owned usable storage capacity. This facility currently stores a mix of refined products, blendstocks, heavy oils and crude oil. This facility receives and distributes products by pipeline, truck, rail, barge and ship. An advantage of our Galena Park facility is that it provides our customers with access to multiple common carrier pipelines, deep-water port facilities that accommodate both ship and barge traffic and loading and unloading facilities for trucks and rail cars.

Our New Haven, Connecticut marine terminal is located on the Long Island Sound near the New York Harbor and has approximately four million barrels of usable storage capacity and primarily handles heating oil, refined products, asphalt, ethanol and biodiesel. This facility receives and distributes products by pipeline, ship, barge and truck.

Our Marrero, Louisiana marine terminal is located on the Mississippi River and has approximately three million barrels of usable storage capacity. This facility primarily handles heavy oils, distillates and asphalt. We receive products at our Marrero terminal by rail, ship and barge and deliver products from Marrero by rail, ship, barge and truck.

Our Wilmington, Delaware marine terminal is located at the Port of Wilmington along the Delaware River. The facility includes almost three million barrels of usable storage and primarily handles refined products, ethanol, heavy oils and crude oil. We receive products at our Wilmington terminal by pipeline, ship and barge and deliver products from this facility by truck, ship and barge.

Our Corpus Christi, Texas marine terminal is located near local refineries and petrochemical plants and includes almost two million barrels of usable storage capacity utilized for heavy oils and feedstocks. We receive and deliver products at our Corpus Christi facility primarily by ship, barge, truck and pipeline.

Joint Venture Activities. We own a 50% interest in Texas Frontera, which owns approximately one million barrels of storage at our Galena Park terminal. This storage is contracted under a long-term agreement with an affiliate of Texas Frontera. In addition to our portion of the net earnings of the joint venture, which we recognize as earnings of non-controlled entities, we receive a fee for operating the storage tanks of Texas Frontera, which we recognize as affiliate management fee revenue on our consolidated statements of income.

Markets and Competition. 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.

We believe the continued strong demand for storage and ancillary services at our marine terminals results from our cost-effective distribution services and key transportation links. The ancillary services we provide at our marine terminals, such as product heating, blending, mixing and additive injection, attract additional demand for our storage services and result in additional revenue opportunities. Demand can be influenced by projected changes in and volatility of petroleum product prices.

Customers and Contracts. We have long-standing relationships with refineries, suppliers and traders at our marine terminals. During 2016, approximately 93% of our storage terminal capacity was utilized with the remaining 7% not utilized primarily due to tank integrity work throughout the year. As of December 31, 2016, approximately 80% of our usable storage capacity was under contracts with remaining 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 three years as of December 31, 2016. These contracts obligate the customer to pay for terminal capacity reserved even if not used by the customer.

GENERAL BUSINESS INFORMATION

Major Customers

One customer accounted for 12% of our consolidated total revenue in 2014. The majority of these revenues resulted from the sale of refined products that were generated in connection with our butane blending and fractionation activities, which are activities conducted by our refined products segment. No other customer accounted for more than 10% of our consolidated revenues during 2014, 2015 and 2016.

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 butane blending and fractionation activities result in us carrying significant levels of petroleum product inventories. In addition, we hold positions related to tender deductions, product gains, crude oil tank bottoms and other crude oil inventories. We use derivative instruments to hedge against commodity price changes and manage risks associated with our various commodity purchase and sale obligations. Our strategies are primarily intended to mitigate and manage price risks that are inherent in our commodity positions. 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 our risks.

Regulation

Interstate Tariff Regulation. Our refined products pipeline system's 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 pipeline rates be filed with the FERC, be posted publicly and be nondiscriminatory and "just and reasonable." 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%. 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. 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 agreement 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 deemed competitive by the FERC, and in both cases these rates can generally be adjusted at our discretion based on market factors.

The Surface Transportation Board, a part of the U.S. Department of Transportation, has jurisdiction over interstate pipeline transportation and rate regulations of ammonia. Transportation rates must be reasonable, and a pipeline carrier may not unreasonably discriminate among its shippers.

Intrastate Tariff Regulation. Some shipments on our refined products and ammonia pipeline systems, and substantially all shipments on our wholly-owned crude oil pipelines, 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, Iowa, Kansas, Minnesota, Nebraska, 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.

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 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 fines of up to $1 million per day per violation.

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 fines of up to the greater of $1 million or triple the monetary gain for violations of its anti-market manipulation regulations.

Should we violate these laws and regulations, we could be subject to material penalties, changes in the rates we can charge and liability to third parties.

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 butane 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 2016 and expect to satisfy the requirements for 2017 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 annually unless adjusted by the EPA. The ability to incorporate increasing volumes of renewable fuel components into fuel products may be limited, which could increase our costs to comply with the RFS standards or limit our ability to blend.

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 bodies of 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 and in accordance with other generally accepted industry standards and practices.

Environmental. Our estimates for remediation liabilities assume that we will be able to use traditionally acceptable remedial 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 remediation 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 or not assessed. 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 $31.4 million and $24.0 million at December 31, 2015 and 2016, respectively. Environmental liabilities have been classified as 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 $2.6 million and $4.1 million at December 31, 2015 and 2016, respectively.

Hazardous Substances and Wastes. In most instances, the environmental laws and regulations affecting our operations relate to the release of hazardous substances or solid wastes into water or soils, and include measures to control pollution of the environment. 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 are being or 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.

As part of our assessment of facility operations, we have identified some above-ground tanks at our terminals that either are or are suspected of being coated with lead-based paints. The removal and disposal of any paints that are found to be lead-based, whenever such activities are conducted in the future as part of our day-to-day maintenance activities, will require increased handling. However, we do not expect the costs associated with this increased handling to be material.

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 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 significantly increase air emissions, obtain and strictly comply with air permits 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, however, that our operations will not be materially adversely affected by such requirements.

Greenhouse Gas Emissions. The EPA has adopted regulations applicable to our facilities 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, in September 2009, the EPA issued a final rule requiring the monitoring and reporting of greenhouse gas emissions from certain large greenhouse gas emissions sources. This reporting rule was expanded in November 2010 to include petroleum facilities. We have adopted procedures for required reporting.

Congress has from time to time considered legislation designed to reduce greenhouse gas emissions. Several states have implemented programs to reduce or monitor greenhouse gas emissions. In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce greenhouse gas emissions. The agreement became effective in November 2016 after more than 70 countries, including the United States, ratified or otherwise indicated their intent to be bound by the agreement.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations that limit or regulate emissions of greenhouse gases could adversely affect demand for the products that we transport, store and distribute and, depending on the particular program adopted, could 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 greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas 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 implementation of regulations.

Finally, certain scientific studies conclude that increasing concentrations of greenhouse gases in the Earth's atmosphere may 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"), and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. PHMSA develops, prescribes and enforces minimum federal safety standards for the transportation of hazardous liquids by pipeline. Congress also enacted the Pipeline Safety Act of 1992, which added the environment to the list of statutory factors that must be considered in establishing safety standards for hazardous liquid pipelines and mandated that regulations be issued to establish criteria for operators to use in identifying and inspecting pipelines located in "high consequence areas" or "HCAs," defined as those areas that are unusually sensitive to environmental damage, cross a navigable waterway or have a high population density. As an operator of hazardous liquid interstate pipelines, we are required to and have developed and follow an integrity management program that provides for assessment of the integrity of all of the portions of our pipelines that could affect designated HCAs. In 1996, Congress enacted the Accountable Pipeline Safety and Partnership Act, which limited the operator identification requirement mandate to pipelines that cross a waterway where a substantial likelihood of commercial navigation exists, required that certain areas where a pipeline release would likely cause permanent or long-term environmental damage be considered in determining whether an area is unusually sensitive to environmental damage and mandated that regulations be issued for the qualification and testing of certain pipeline personnel. In the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, Congress required mandatory inspections for certain U.S. crude oil transmission pipelines in HCAs and mandated that regulations be issued for low-stress hazardous liquid pipelines and pipeline control room management. Our assets are also subject to various federal security regulations, and we believe we are in substantial compliance with all applicable federal regulations.

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. We believe we are in substantial compliance with all applicable state regulations.

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

Breakout Storage Tank Integrity Regulations. PHMSA defines a breakout tank as one that is used to relieve surges in a hazardous liquid pipeline system or to receive and store hazardous liquids transported by a pipeline for reinjection and continued transportation by a pipeline. In January 2015, amended regulations were published by PHMSA which require more frequent out-of-service inspections for breakout storage tanks. These regulations would impact approximately 550 of our storage tanks. We remain in active discussions with PHMSA to consider alternative, technically-viable inspection intervals. If we are unable to reach such an agreement with PHMSA, our compliance with the amended regulations could negatively impact our future financial results and could result in service disruptions to our customers.

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, state and local governmental authorities and local citizens upon request. At qualifying facilities, we are subject to OSHA Process Safety Management regulations that are designed 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.

The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 increased penalties for safety violations, established additional safety requirements for newly-constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. PHMSA has also published notices and advanced notices of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements, and recently finalized revisions to its hazardous liquid pipeline regulations in January 2017. Compliance with such legislative and regulatory changes could increase our regulatory compliance costs and have a material adverse effect on our results of operations.

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. 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 these 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 by us or our predecessor, 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, 2016, we had 1,747 employees, 930 of which were assigned to our refined products segment and concentrated in the central U.S. Approximately 24% of the 930 employees are represented by the United Steel Workers ("USW") and covered by a collective bargaining agreement that expires in January 2019. At December 31, 2016, 141 of our employees were assigned to our crude oil segment and were concentrated in the central U.S., and none of these employees were covered by a collective bargaining agreement. The labor force of 171 employees assigned to our marine storage segment at December 31, 2016 was primarily located in the Gulf and East Coast regions of the U.S. Approximately 17% of these employees are represented by the International Union of Operating Engineers ("IUOE") and covered by a collective bargaining agreement that expires in October 2020.

(d) Financial Information About Geographical Areas

We have no international activities. For all periods included in this report, all of our revenue was derived from operations conducted in, and all of our assets were located in, the U.S. See Note 16–*Segment Disclosures* in the notes to consolidated financial statements included in Item 8 of this report for information regarding our revenue and total assets.

(e) Available Information

We file annual, quarterly and current reports, proxy statements and other information electronically with the Securities and Exchange Commission ("SEC"). You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC, including our filings.

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.

Item 1A. ***Risk Factors***

The nature of our business activities subjects us to a wide variety of hazards and risks. The following is a summary of the material risks relating to our business activities that we have identified. In addition to the factors discussed elsewhere in this Annual Report on Form 10-K, you should carefully consider the risks and uncertainties described below, which could have a material adverse effect on our business, financial condition or results of operations. However, these risks are not the only risks that we face. Our business could be impacted by additional risks and uncertainties not currently known or that we currently believe to be immaterial. If any of these risks actually occur, they could materially harm our business, financial condition or results of operations and impair our ability to implement our business plans or complete development projects as scheduled.

Risks Related to Our Business

Our cash distributions are not guaranteed. The cash from operations that we generate could decrease or fail to meet expectations, either of which could reduce our ability to pay quarterly cash distributions.

The amount of cash we can distribute to our limited partners principally depends upon the cash we generate from our operations, as well as cash reserves established by our general partner. Our distributable cash flow does not depend solely on profitability, which is affected by non-cash items. As a result, we could pay cash distributions during periods when we record net losses and could be unable to pay cash distributions during periods when we record net income. In addition, the amount of cash we generate from operations is affected by numerous factors beyond our control, fluctuates from quarter to quarter and may change over time. Significant or sustained reductions in the cash generated by our operations could reduce our ability to pay quarterly distributions. Any failure to pay distributions at expected levels could result in a loss of investor confidence and a decrease in the value of our unit price.

Our financial results depend on the demand for the petroleum products that we transport, store and distribute, among other factors. Unfavorable economic conditions, technological changes, regulatory developments or other factors could result in lower demand for these products for a sustained period of time.

Any sustained decrease in demand for petroleum products in the markets served by our pipelines or terminals could result in a significant reduction in the volume of products that we transport, store or distribute, and thereby reduce our cash flow and our ability to pay cash distributions. Global economic conditions have from time to time resulted in reduced demand for the products transported and stored by our pipelines and terminals and consequently for the services that we provide. Our financial results may also be affected by uncertain or changing economic conditions within certain regions, or by supply or demand shifts between regions. If economic and market conditions remain uncertain or adverse conditions persist for an extended period, we could experience material impacts to our business, financial condition or results of operations.

Other factors that could lead to a decrease in demand for the petroleum products we transport, store and distribute include:

- an increase or decrease in the market prices of petroleum products, which may reduce supply or demand. Market prices for petroleum products are subject to wide fluctuations in response to changes in global and regional supply and demand over which we have no control. For example, legislation was passed in 2015 that removed the ban on crude oil exports from the U.S., which could impact the demand for our services in ways that we are unable to predict or control;

- higher fuel taxes or other governmental or regulatory actions that increase the cost of the products we handle;

- an increase in transportation fuel economy, whether as a result of a shift by consumers to more fuel-efficient vehicles, technological advances by manufacturers or federal or state regulations. For example, the National Highway Traffic Safety Administration and the EPA finalized standards for passenger cars and light trucks manufactured in model years beginning in 2017 that will require significant increases in fuel efficiency. These standards are intended to reduce demand for petroleum products, and could reduce demand for our services; and

- an increase in the use of alternative fuel sources, such as ethanol, biodiesel, natural gas, fuel cells, solar, electric and battery-powered engines. Current laws require a significant increase in the quantity of ethanol and biodiesel used in transportation fuels between now and 2022. Increases in domestic natural gas production have resulted in lower U.S. natural gas prices, which in turn has led to the promotion by the natural gas industry and some politicians of natural gas as an alternative transportation fuel. Increases in the use of such alternative fuels could have a material impact on the volume of petroleum-based fuels transported on our pipelines or distributed through our terminals.

A decrease in crude oil production in the basins served by our crude oil pipelines could reduce our transportation revenues, which could adversely impact our results of operations and the amount of cash we generate.

Numerous factors can cause reductions in crude oil production in the regions served by our pipelines, including, among other factors, lower overall crude oil prices, regional price or quality differences, higher costs of crude oil production, weather or other natural causes, adverse regulatory or legal developments, disruptions in financial or credit markets that inhibit the ability of our customers to finance the costs of production, or lower overall demand for crude oil and the products derived from crude oil. Crude oil prices have historically exhibited significant volatility, and are influenced by, among other factors, worldwide and domestic supplies of and demand for crude oil, political and economic developments in often-volatile producing regions, actions taken by the Organization of Petroleum Exporting Countries, technological developments, government regulations and taxes, policies regarding the importing and exporting of crude oil and conditions in global financial markets. In 2014 and 2015, average crude oil prices fell dramatically, as both domestic and international production increased while global economic conditions weakened, resulting in global crude supply that significantly exceeded global crude demand. Many producers, including some of our customers, responded to this oversupply situation by curtailing production or new investments in future production. We are unable to predict future prices of crude oil or what impact the crude price environment will have on future production overall, and specifically on production in the basins we serve. While the transportation revenues on our crude oil pipelines are in some cases supported by long-term contracts, lower production in the regions served by our pipelines could result in lower shipments of uncommitted volumes, or could cause us to be unable to renew our contracts at existing volumes or rates. Any sustained decrease in the production of crude oil in the regions served by our crude oil pipelines could result in a significant reduction in the volume of products that we transport or the rates we are able to charge for such transportation services or both, thereby reducing our cash flow and our ability to pay cash distributions.

We depend on producers, gatherers, refineries and petroleum pipelines owned and operated by others to supply our assets.

We depend on crude oil production and on connections with gathering systems, refineries and petroleum pipelines owned and operated by third parties to supply our assets. We cannot control or predict the amount of crude oil that will be delivered to us by the gathering systems and pipelines that supply our crude oil assets, nor can we control or predict the output of refineries that supply our refined products pipelines and terminals. Changes in the quality or quantity of this crude oil production, outages at these refineries or reduced or interrupted throughput on these gathering systems or pipelines due to weather-related or other natural causes, competitive forces, testing, line repair, damage, reduced operating pressures or other causes could reduce shipments on our pipelines or result in our being unable to receive products at or deliver products from our terminals or receive products for processing at our condensate splitter, any of which could materially adversely affect our cash flows and ability to pay cash distributions.

The closure of refineries that supply or are supplied by our refined products and crude oil pipelines could result in material disruptions or reductions in the volumes we transport and store and in the amount of cash we generate.

Refineries that supply or are supplied by our facilities are subject to regulatory developments, including but not limited to regulations regarding fuel specifications, plant emissions and safety and security requirements that could significantly increase the cost of their operations and reduce their operating margins. In addition, the profitability of the refineries that supply our facilities is subject to regional and global supply and demand dynamics that are difficult to predict. A period of sustained weak demand or increased cost of supply could make refining uneconomic for some refineries, including those located along our refined products and crude oil pipelines. The closure of a refinery that delivers product to or receives crude from our refined products or crude oil pipelines could reduce the volumes we transport and the amount of cash we generate. Further, the closure of these or other refineries could result in our customers electing to store and distribute petroleum products through their proprietary terminals, which could result in a reduction of our storage volumes.

A decrease in contract renewals or renewals at substantially lower rates could cause our storage revenue to decline, which could adversely impact our results of operations and the amount of cash we generate.

The revenue we earn from providing storage at our marine and crude oil terminals and along our pipeline system is provided for in contracts negotiated with our storage customers. Many of those contracts are for multi-year periods and require our customers to pay a fixed rate for storage capacity regardless of market conditions during the contract period. Changing market conditions, including changes in petroleum product supply or demand patterns, forward-price structure, financial market conditions, regulations, accounting rules or other factors could cause our customers to be unwilling to renew their storage contracts with us when those contracts terminate, or make them willing to renew only at lower rates or for shorter contract periods. Failure by our customers to renew their storage contracts on terms and at rates substantially similar to our existing contracts could result in lower utilization of our facilities and could cause our storage revenue to be more volatile. We have built a significant amount of new storage to meet market demand in recent years, as have several of our competitors. In addition, storage facilities previously used to support refineries or other facilities have in some cases been redeployed to provide services that compete with our own services. Increased competition from other storage facilities could discourage our customers from renewing their contracts with us or cause them to renew their contracts with us at lower rates. We typically make capital investments in storage facilities only if we are able to secure contracts from our customers that support such investment; however, in some cases the initial term of those contracts is not sufficient to ensure that we fully earn the return we expect on those investments. If our customers do not renew such contracts or renew on less favorable terms, we could earn a return on those investments that is below our cost of capital, which could adversely affect our results of operations, financial position or cash flows.

Competition could lead to lower levels of profits and reduce the amount of cash we generate.

We compete with other existing pipelines and terminals that provide similar services in the same markets as our assets. Some of our competitors also offer additional services that we do not offer, which could make our services less competitive. In addition, our competitors could construct new assets or redeploy existing assets in a manner that would result in more intense competition in the markets we serve. We compete with other transportation, storage and distribution alternatives on the basis of many factors, including but not limited to rates, service levels and offerings, geographic location, connectivity and reliability. Our customers could utilize the assets and services of our competitors instead of our assets and services, or we could be required to lower our prices or increase our costs to retain our customers, either of which could materially adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

Our business is subject to the risk of a capacity overbuild in some of the markets in which we operate.

We have made and continue to make significant investments in new energy infrastructure to meet market demand, as have several of our competitors. For example, we have invested significantly in pipelines to deliver crude oil from the Permian Basin in West Texas to markets along the U.S. Gulf Coast and from the DJ Basin in Colorado to Cushing, Oklahoma. We have also constructed a condensate splitter in Corpus Christi, Texas, and are in the process of constructing a new marine terminal along the Houston Ship Channel in Pasadena, Texas. Similar investments have been made and additional investments may be made in the future by our competitors or by new entrants to the markets we serve. The success of these and similar projects largely relies on the realization of anticipated market demand, and these projects typically require significant development periods, during which time demand for such infrastructure may change, or additional investments by competitors may be made. If infrastructure investments by us or others in the markets we serve result in capacity that exceeds the demand in those markets, our facilities could be underutilized, we could be forced to reduce the rates we charge for our services, the value of our assets could decrease and the returns on our investments in those markets could fail to meet our expectations.

Mergers among our customers and competitors could result in lower volumes being shipped on our pipelines or products stored in or distributed through our terminals, thereby reducing the amount of cash we generate.

Mergers among our existing customers and our competitors could provide strong economic incentives for the combined entities to utilize their existing systems instead of ours in those markets where our systems compete. As a result, we could lose some or all of the volumes and associated revenue from these customers, and we could experience difficulty in replacing those lost volumes and revenue. As a significant portion of our operating costs are fixed, a reduction in volumes would result not only in less revenue, but also a decline in cash flow of a similar magnitude, which could materially adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

Reduced volatility in energy prices or new government regulations could discourage our storage customers from holding positions in petroleum products, which could adversely affect the demand for our storage services.

We have constructed and continue to build new storage tanks in response to increased customer demand for storage. Many of our competitors have also built new storage facilities. The demand for new storage has resulted in part from our customers' desire to have the ability to take advantage of profit opportunities created by volatility in the prices of petroleum products. If the prices of petroleum products become relatively stable, or if federal or state regulations are passed that discourage our customers from storing these commodities, demand for our storage services could decrease, in which case we may be unable to identify customers willing to contract for such services or be forced to reduce the rates we charge for our services, either of which could materially reduce the amount of cash we generate.

Fluctuations in prices of petroleum products that we purchase and sell could materially affect our results of operations.

We generate product sales revenue from our butane blending and fractionation activities, as well as from the sale of product generated by the operations of our pipelines and terminals. We also maintain product inventory related to these activities. Prices of petroleum products have historically experienced wide fluctuations. Significant fluctuations in market prices of petroleum products could result in losses or lower profits from these activities, thereby reducing the amount of cash we generate and our ability to pay cash distributions. Additionally, significant fluctuations in market prices of petroleum products could result in significant unrealized gains or losses on transactions we enter to hedge our exposure to commodity price changes. To the extent these transactions have not been designated as hedges for accounting purposes, the associated unrealized gains and losses directly impact our results of operations.

We hedge prices of petroleum products by utilizing physical purchase and sale agreements, exchange-traded futures contracts or over-the-counter transactions. These hedging arrangements do not eliminate all price risks, could result in fluctuations in quarterly or annual financial results and could result in material cash obligations that could negatively impact our financial position or our ability to pay distributions to our unitholders. Further, any non-compliance with our risk management policies could result in significant losses.

We hedge our exposure to price fluctuations for our petroleum products purchase and sale activities by utilizing physical purchase and sale agreements, exchange-traded futures contracts or over-the-counter transactions. To the extent these hedges do not qualify for hedge accounting treatment or are not designated as hedges under Accounting Standards Codification 815, *Derivatives and Hedging*, or if they result in material amounts of ineffectiveness, we could experience material fluctuations in our quarterly or annual results of operations. We may be required to post margin in connection with these hedges, which could result in material and unpredictable demands on our liquidity. These contracts may be for the purchase or sale of product in markets for a time frame different from those in which we are attempting to hedge our exposure, resulting in hedges that do not eliminate all price risks. In addition, our product sales and hedging operations involve the risk of non-compliance with our risk management policies. We cannot assure you that our processes and procedures will detect and prevent all violations of our risk management policies, particularly if deception or other intentional misconduct is involved. If we incur a material loss related to commodity price risks, including non-compliance with our risk management policies, our quarterly or annual results of operations or cash flows could be negatively impacted, which could have a negative impact on our unit price. Further, our requirement to post material amounts of margin in connection with our hedges could negatively impact our liquidity and our ability to pay distributions to our unitholders.

Changes in price levels could negatively impact our revenue, our expenses, or both, which could adversely affect our results from operations, our liquidity and our ability to pay cash distributions.

The operation of our assets and the implementation of our growth strategy require significant expenditures for labor, materials, property, equipment and services. Increases in the cost of these items could materially increase our expenses or capital costs. We may not be able to pass these increased costs on to our customers in the form of higher fees for our services.

We use the FERC's PPI-based price indexing methodology to establish tariff rates in certain markets served by our pipelines. The FERC's indexing methodology is subject to review every five years and limits a pipeline's rates each year to a new ceiling level, which is calculated as the previous year's ceiling level multiplied by a percentage. For the five-year period beginning July 1, 2016, the indexing method provides for annual changes equal to the change in the PPI-FG plus 1.23%. This methodology could result in changes in our revenue that do not fully reflect changes in the costs we incur to operate and maintain our pipelines. For example, our costs could increase more quickly or by a greater amount than the PPI-FG index plus 1.23% used by the new FERC methodology. Further, in periods of general price deflation, the ceiling level provided for by the FERC's index methodology could decrease, as it recently did in 2015, requiring us to reduce our index-based rates, as we did in July 2016, even if the actual costs we incur to operate our assets increase. Changes in price levels that lead to decreases in our revenue or increases in the prices we pay to operate and maintain our assets could adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

Our business involves many hazards and operational risks, the occurrence of which could materially adversely affect our results of operations, financial position or cash flows and our ability to pay cash distributions.

Our operations are subject to many hazards inherent in the transportation and distribution of petroleum products and ammonia, including ruptures, leaks and fires. For example, in 2016, we experienced a release of anhydrous ammonia on our ammonia pipeline system near Tekamah, Nebraska. The release resulted in a fatality and other damages. Additionally, our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and earthquakes. Our storage and pipeline facilities located near the U.S. Gulf Coast, for example, have historically experienced damage and interruption of business due to hurricanes. These risks could result in substantial losses due to personal injury or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage, and may result in curtailment or suspension of our related operations. Some of our assets are located in or near high consequence areas such as residential and commercial centers or sensitive environments, and the potential damages are even greater in these areas. If a significant accident or event occurs, it could materially adversely affect our results of operations, financial position or cash flows and our ability to pay cash distributions.

Our assets may not be adequately insured or we could experience losses that exceed our insurance coverage.

We are not fully insured against all hazards or operational risks related to our businesses, and the insurance we carry requires that we meet certain deductibles before we can collect for any losses we sustain. If a significant accident or event occurs that is not fully insured, it could materially adversely affect our results of operations, financial position or cash flows and our ability to pay cash distributions.

We may encounter increased costs related to and decreases in the availability of insurance.

Premiums and deductibles for our insurance policies could escalate as a result of market conditions or losses experienced by us or by other companies. In some instances, insurance could become unavailable or available only for reduced amounts of coverage. Increases in the cost of insurance or the inability to obtain insurance at rates that we consider commercially reasonable could materially affect our results of operations, financial position or cash flows and our ability to pay cash distributions.

Many of our storage tanks and significant portions of our pipeline system have been in service for several decades.

Our pipeline and storage assets are generally long-lived assets. As a result, some of our assets have been in service for several decades. The age and condition of these assets could result in increased maintenance or remediation expenditures and an increased risk of product releases and associated costs and liabilities. Any significant increase in these expenditures, costs or liabilities could materially adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

We do not own most of the property on which our pipelines are constructed, and we rely on securing and retaining adequate rights-of-way and permits in order to operate our existing assets and complete growth projects.

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the relevant 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. Several rights-of-way for our pipelines and other real property assets are shared with other pipelines and 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 right-of-way grants. We are required to obtain 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. Similarly, we have obtained permits from railroad companies to cross over or under certain lands or rights-of-way, many of which are also revocable at the grantor's election. We are subject to potential increases in costs under our agreements with landowners, and if any of our rights-of-way or permits were revoked, our operations could be disrupted or we could be required to relocate our pipelines. Similarly, if we are unable to secure rights-of-way required for our growth projects, we could be forced to re-design or re-route those projects, which could result in substantial delays, reduced revenue or increased costs on those projects. Our ability to exercise the power of eminent domain varies by state and by circumstance, and the availability of the power and the compensation we must provide landowners in connection with any eminent domain action may be determined by a court. Failure to obtain required new rights-of-way or permits or retain rights-of-way and permits on existing terms could have a material adverse effect on our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

Terrorist attacks aimed at our facilities or that impact our customers or the markets we serve could adversely affect our business.

The U.S. government has issued warnings that energy assets in general, and the nation's pipeline and terminal infrastructure in particular, may be targets of terrorist organizations. The threat of terrorist attacks subjects our operations to increased risks. Any terrorist attack on our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business. Similarly, any terrorist attacks that severely disrupt the markets we serve could materially adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

Cyber attacks, or other information security breaches, that circumvent security measures taken by us or others with whom we conduct business or share information could result in increased costs or other damage to our business.

We operate our assets and manage our businesses using a telecommunications network. A security breach of that network could result in improper operation of our assets, potentially including contamination or degradation of the products we transport, store or distribute, delays in the delivery or availability of our customers' product or releases of petroleum products for which we could be held liable. In addition, we rely on third-party systems, including for example the electric grid, which could also be subject to security breaches or cyber attacks, and the failure of which could have a significant adverse effect on the operation of our assets. We and the operators of the third-party systems on which we depend may not have the resources or technical sophistication to anticipate or prevent every emerging type of cyber attack, and such an attack, or additional measures taken to prevent such an attack, could adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

We also collect and store sensitive data on our networks, including our proprietary business information and information about our customers, suppliers and other counterparties, and personally identifiable information of our employees. The secure maintenance of this information is critical to our operations. Despite our security measures, our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. We do not maintain specialized insurance for such attacks. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, disruption of our operations, or damage to our reputation, any of which could adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

Failure of critical information technology systems may impact our ability to operate our assets or manage our businesses, thereby reducing the amount of cash available for distribution.

We utilize information technology systems to operate our assets and manage our businesses. Some of these systems are proprietary systems that require specialized programming capabilities, while others are based upon or reside on technology that has been in service for many years. Failures of these systems could result in a breach of critical operational or financial controls and lead to a disruption of our operations, commercial activities or financial processes. Such failures could adversely affect our results of operations, financial position or cash flow, as well as our ability to pay cash distributions.

Our expansion projects may not immediately produce operating cash flows and may exceed our cost estimates or experience delays.

We have undertaken numerous large expansion projects that have required and will continue to require us to make significant capital investments. We intend to finance those projects primarily with new borrowings, and we will incur financing costs during the planning and construction phases of these projects; however, the operating cash flows we expect these projects to generate will not materialize until sometime after the projects are completed, if at all. As a result, our leverage ratio relative to our earnings may increase during the period prior to the generation of those operating cash flows. In addition, the amount of time and investment necessary to complete these projects could materially exceed the estimates we used when determining whether to undertake them. For example, we must compete with other companies for the materials and construction services required to complete these projects, and competition for these materials or services could result in significant delays or cost overruns. Similarly, we must secure and retain required permits and rights-of-way, including in some cases through the exercise of the power of eminent domain, in order to complete and operate these projects, and our inability to do so in a timely manner could result in significant delays or cost overruns. Our ability to secure required permits and rights-of-way or otherwise proceed with construction of our expansion projects could encounter opposition from political activists, who may attempt to delay pipeline construction through protests and other means, as has recently occurred in North Dakota in relation to the Dakota Access Pipeline ("DAPL"). Further, in many instances the operations of our expansion projects are subject to the execution by third parties of pipeline connections or other related projects that are beyond our control. Delays or unanticipated costs associated with these third parties in the execution of these related projects could result in delays or cost overruns in the start-up of our own projects. In addition, we run the risk of failing to meet commitments to our customers as a result of project delays, which in some cases could allow our customers to terminate their commitments to us or otherwise negatively impact customer relationships and future financial results. Any cost overruns or unanticipated delays in the completion or commercial development of our expansion projects could reduce the anticipated returns on these projects, which in turn could materially increase our leverage and reduce our liquidity and our ability to pay cash distributions.

Potential future acquisitions and expansions may affect our business by substantially increasing the level of our indebtedness and liabilities, subjecting us to the risk of being unable to effectively integrate the new operations and diluting our limited partner unitholders.

From time to time we evaluate and acquire assets and businesses. We may issue significant amounts of additional equity securities and incur substantial additional indebtedness to finance future acquisitions, and our capitalization and results of operations may change significantly as a result. Our limited partner unitholders may not have an opportunity to review or evaluate the information and assumptions we use to determine whether to pursue an acquisition. An acquisition that we expect to be accretive could nevertheless reduce our cash from operations if we rely on faulty information, make inaccurate assumptions, assume unidentified liabilities or otherwise improperly value the acquired assets. In addition, any equity securities we issue to finance acquisitions would dilute our existing limited partner unitholders and could reduce our cash flow available for distribution on a per unit basis.

Acquisitions and business expansions involve numerous risks, including but not limited to difficulties in the assimilation of the assets and operations of the acquired businesses, inefficiencies and difficulties that arise due to our unfamiliarity with new assets and the businesses associated with them and their markets, challenges in managing or retaining new employees and establishing relationships with and retaining new customers and business partners, and the diversion of management's attention from other business concerns. Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. Following an acquisition, we may discover previously unknown liabilities associated with the acquired business for which we have no recourse from the seller.

We compete for acquisitions and new projects with numerous other established energy companies and many other potential investors. Increased competition for acquisitions or growth projects could limit our ability to execute our growth strategy or could result in our executing that strategy on substantially less attractive terms than we have previously experienced, either of which could have a material adverse effect on our results of operations or cash flows, as well as our ability to pay cash distributions.

Failure to generate or complete additional growth projects or make future acquisitions could reduce our ability to increase cash distributions to our unitholders.

Our ability to increase distributions to our unitholders depends to a significant degree on our ability to successfully identify and execute additional growth projects and acquisitions. We face significant uncertainties and competition in the pursuit of such opportunities. For example, decisions regarding new growth projects rely on numerous estimates, including among other factors, predictions of future demand for our services, future supply shifts, crude oil production estimates, commodity price environments, regulatory developments, economic conditions and potential changes in the financial condition of our customers. Our predictions of such factors could cause us to forego certain investments or to lose opportunities to competitors who make investments based on more aggressive predictions. Valuations of energy infrastructure assets have generally been elevated in recent years, which has made it difficult for us to be successful in our attempts to acquire new assets, as other bidders for those assets have been willing to pay prices and accept terms that did not meet our risk and return criteria. If we are unable to acquire new assets or develop additional expansion projects, our ability to increase distributions to our unitholders will be reduced.

We do not have the same flexibility as other types of organizations to accumulate cash and retained earnings to protect against illiquidity in the future, and we rely on access to capital to fund acquisitions and growth projects and to refinance existing debt obligations. Unfavorable developments in capital markets could limit our ability to obtain funding or require us to secure funding on terms that could limit our financial flexibility, reduce our liquidity, dilute the interests of our existing unitholders and reduce our cash flows and ability to pay distributions.

Our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash, after taking into account reserves for commitments and contingencies, including capital investments, operating costs and debt service requirements. As a result, we do not accumulate equity in the form of retained earnings in a manner typical of many other forms of organization, including most traditional public corporations. As a result, we are more likely than those organizations to require issuances of additional capital to finance our growth plans, meet unforeseen cash requirements and service our debt.

We regularly consider and pursue growth projects and acquisitions as part of our efforts to increase cash available for distribution to our unitholders. These transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets and operations. For example, we estimate that we will spend approximately $900 million to complete our current slate of organic growth projects. We generally do not retain sufficient cash flow to finance such projects and acquisitions, and consequently the execution of our growth strategy requires regular access to external sources of capital. Any limitations on our access to capital on satisfactory terms will impair our ability to execute this strategy and could reduce our liquidity and our ability to make cash distributions.

Similarly, we generally do not retain sufficient cash flow to repay our indebtedness when it matures, and we rely on new capital to refinance these obligations. For example, $250 million of our long-term notes will mature in July 2018 and an additional $550 million will mature in 2019. We anticipate raising new capital to refinance those notes when they mature.

Limitations on our access to capital, including on our ability to issue additional debt and equity, could result from events or causes beyond our control, and could include, among other factors, decreases in our creditworthiness or profitability, significant increases in interest rates, increases in the risk premium generally required by investors or in the premium required specifically for investments in energy-related companies or master limited partnerships, and decreases in the availability of credit or the tightening of terms required by lenders. Any limitations on our ability to refinance these obligations by securing new capital on satisfactory terms could severely limit our liquidity, our financial flexibility or our cash flows, and could result in the dilution of the interests of our existing unitholders.

Increases in interest rates could increase our financing costs, reduce the amount of cash we generate and adversely affect the trading price of our units.

As of December 31, 2016, the face value of our outstanding fixed-rate debt was $4.1 billion. We had floating-rate borrowings of $50 million outstanding as of December 31, 2016 under our commercial paper program, and we expect to make additional floating rate borrowings under our commercial paper program or revolving credit facility as needed. As a result, we would have exposure to changes in short-term interest rates. We may also use interest rate derivatives to effectively convert some of our fixed-rate notes to floating-rate debt, thereby increasing our exposure to changes in short-term interest rates. In addition, the execution of our growth strategy and the refinancing of our existing debt could require that we issue additional fixed-rate debt, and consequently we also have potential exposure to changes in long-term interest rates. Rising interest rates could reduce the amount of cash we generate and materially adversely affect our liquidity and our ability to pay cash distributions. Moreover, the trading price of our units is sensitive to changes in interest rates and could be materially adversely affected by any increase in interest rates.

Restrictions contained in our debt instruments may limit our financial flexibility.

We are subject to restrictions with respect to our debt that may limit our flexibility in structuring or refinancing existing or future debt and may prevent us from engaging in certain beneficial transactions. These restrictions include, among other provisions, the maintenance of certain financial ratios, as well as limitations on our ability to incur additional indebtedness, to grant liens or to repay existing debt without prepayment premiums. These restrictions could result in higher costs of borrowing and impair our ability to generate additional cash.

The amount and timing of distributions to us from our joint ventures is not within our control, and we may be unable to cause our joint ventures to take or refrain from taking certain actions that may be in our best interest. In addition, as construction manager and operator of the majority of our joint ventures, we are exposed to additional risk and liability in connection with our responsibilities in those capacities.

As of December 31, 2016, we were engaged in seven joint ventures in which we share control with other entities according to the relevant joint venture agreements. Those agreements provide that the respective joint venture management committees, including our representatives along with the representatives of the other owners of those joint ventures, determine the amount and timing of distributions. Our joint ventures could establish separate financing arrangements that could contain restrictive covenants that may limit or restrict the joint venture's ability to make cash distributions to us under certain circumstances. Any inability to generate cash or restrictions on cash distributions we receive from our joint ventures could impair our results of operations, cash flows and our ability to pay cash distributions.

In the case of Double Eagle and Seabrook, an affiliate of our joint venture co-owner serves as operator, and consequently we rely on affiliates of our joint venture co-owner for many of the management functions of those joint ventures. Without the cooperation of the other owners of those joint ventures, we may not be able to cause our joint ventures to take or not to take certain actions, even though those actions or inactions may be in the best interest of us or the particular joint venture. With respect to our other joint ventures, we are the construction manager and operator, which exposes us to additional risk and liability in connection with our responsibilities in those capacities.

If we are unable to agree with our joint venture co-owners on a significant matter, it could result in delays, litigation or operational impasses that could result in a material adverse effect on that joint venture's financial condition, results of operations or cash flows. If the matter is significant to us, it could result in a material adverse effect on our results of operations, financial position or cash flows. If we fail to make a required capital contribution, we could be deemed to be in default under the applicable joint venture agreement. Our joint venture co-owners may be permitted to pursue a variety of remedies, including funding any deficiency resulting from our failure to make such capital contribution, which would result in a dilution of our ownership interest, or, in some cases, our joint venture co-owners may have the option to purchase all of our existing interest in the subject joint venture.

Moreover, subject to certain limitations in the respective joint venture agreements, any joint venture owner may sell or transfer its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint venture owners. Any such transaction could result in our being co-owners with different or additional parties with whom we have not had a previous relationship.

We are exposed to counterparty risk. Nonpayment, commitment termination or nonperformance by our customers, vendors, joint venture co-owners, lenders or derivative counterparties could materially reduce our revenue, increase our expenses, impair our liquidity or otherwise negatively impact our results of operations, financial position or cash flows and our ability to pay cash distributions.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers to whom we extend credit. In addition, we frequently undertake capital expenditures based on commitments from customers from which we expect to realize the expected return on those expenditures, including take-or-pay commitments from our customers, and nonperformance by our customers of those commitments or termination of those commitments resulting from our inability to timely meet our obligations could result in substantial losses to us. Recently, our sole customer for our Corpus Christi condensate splitter terminated our tolling agreement, and we are pursuing legal remedies based on our belief that the termination was a breach of its obligations. In addition, we are constructing a new marine terminal along the Houston Ship Channel in Pasadena, Texas at a cost of $335 million based on the commitment of a single customer. Nonperformance by customers who back our capital projects could significantly impact our expected return from those projects.

We have undertaken numerous projects that require cooperation with and performance by joint venture co-owners. For example, Seabrook will be operated by our joint venture co-owner, LBC Tank Terminals, LLC, which also must make capital contributions to the joint venture. Nonperformance by our joint venture co-owners could result in increased costs or delays that could decrease our returns on our joint venture projects.

We utilize third-party vendors to provide various functions, including, for example, certain construction activities, engineering services, facility inspections and operation of certain software systems. Using third parties to provide these functions has the effect of reducing our direct control over the services rendered. The failure of one or more of our third-party providers to deliver the expected services on a timely basis at the prices we expect and as required by contract could result in significant disruptions, costs to our operation, or instances of a contractor's non-compliance with applicable laws and regulations, which could materially adversely affect our business, financial condition, operating results or cash flows.

We also rely to a significant degree on the banks that lend to us under our revolving credit facility for financial liquidity, and any failure of those banks to perform on their obligations to us could significantly impair our liquidity. Furthermore, nonpayment by the counterparties to our interest rate and commodity derivatives could expose us to additional interest rate or commodity price risk.

Any take-or-pay commitment terminations or substantial increase in the nonpayment or nonperformance by our customers, vendors, lenders or derivative counterparties could have a material adverse effect on our results of operations, financial position or cash flows and our ability to pay cash distributions.

Losses sustained by any money market mutual fund or other investment vehicle in which we invest our cash or the failure of any bank or financial institution in which we deposit funds could adversely affect our financial position and our ability to pay cash distributions.

We may maintain material balances of cash and cash equivalents for extended periods of time. We typically invest any material amount of cash on hand in cash equivalents such as money market mutual funds. These funds are primarily comprised of highly rated short-term instruments. Significant market volatility and financial distress could cause such investments to lose value or reduce the liquidity of such investments. We may also maintain deposits at a commercial bank in excess of amounts insured by government agencies such as the Federal Deposit Insurance Corporation. In addition, certain exchange-traded derivatives transactions we enter into in order to hedge commodity-related price exposures frequently require us to make margin deposits with a broker. A failure of our commercial bank or our broker could result in our losing any funds we have deposited. Any losses we sustain on the investments or deposits of our cash could materially adversely affect our financial position and our ability to pay cash distributions.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies, rate regulation or challenges by shippers of the rates we charge on our refined products and crude oil pipelines may reduce the amount of cash we generate.

The FERC regulates the rates we can charge, and the terms and conditions we can offer, for interstate transportation service on our refined products and crude oil pipelines. State regulatory authorities regulate the rates we can charge, and the terms and conditions we can offer, for intrastate movements on our refined products and crude oil pipelines. The determination of the interstate or intrastate character of shipments on our petroleum products pipelines may change over time, which may change the rates we are allowed to charge for transportation and other related services. Shippers may protest our pipeline tariff filings, and the FERC or state regulatory authorities may investigate tariff rates. Further, other than for rates set under market-based rate authority, the FERC may order refunds of amounts collected under rates that are determined to be in excess of a just and reasonable level when taking into consideration our pipeline system's cost-of-service. State regulatory authorities could take similar measures for intrastate tariffs. In addition, shippers may challenge by complaint the lawfulness of tariff rates that have become final and effective. The FERC and state regulatory authorities may also investigate tariff rates absent shipper complaint. If existing rates challenged by complaint are determined to be in excess of a just and reasonable level when taking into consideration our pipeline systems' cost-of-service, we could be required to pay refunds to shippers and make other concessions.

The FERC's ratemaking methodologies may limit our ability to set rates based on our true costs or may delay the use of rates that reflect increased costs. The FERC's primary ratemaking methodology applicable to us is price indexing. We use this methodology to establish our rates in approximately 40% of the markets for our refined products pipeline. The FERC's indexing methodology is subject to review every five years and currently requires a pipeline to change its rates each year to a new ceiling level, which is calculated as the previous year's ceiling level multiplied by a percentage. For the five-year period beginning July 1, 2016, the indexing method provides for annual changes in rates by a percentage equal to the change in the PPI-FG plus 1.23%. When the ceiling level falls, as it did in 2015, we are required to reduce our rates that are subject to the FERC's price indexing methodology.

The FERC and relevant state regulatory authorities allow us to establish rates based on conditions in individual markets without regard to the FERC's index level or our cost-of-service. We establish market-based rates in approximately 60% of the markets for our refined products pipeline. If we were to lose our market-based rate authority, we would then be required to establish rates on some other basis, such as our cost-of-service.

In October 2016, the FERC issued an advanced notice of proposed rulemaking ("ANOPR") seeking comments on potential revisions to (1) the Commission's policies for evaluating oil pipeline indexed rate changes; and (2) the reporting requirements for page 700 of FERC Form No. 6, Annual Report of Oil Pipeline Companies. While we are unable to predict the ultimate form of rulemaking, if any, that could follow this advanced notice, the potential revisions discussed in the ANOPR could affect our ability to establish rates in a manner consistent with our past practice, while potentially preventing us from recovering increases in the costs we incur to operate our pipelines and likely increasing our cost of complying with FERC reporting requirements.

In July 2016, the D.C. Circuit issued a decision in *United Airlines Inc. v. FERC* that found that FERC had acted arbitrarily and capriciously when it permitted an interstate petroleum products pipeline organized as a limited partnership to include an income tax allowance in its rates. The court remanded the case to the FERC to allow it to have an opportunity to provide a reasoned basis for its decision on income tax allowances for partnership pipelines. We are unable to predict how the FERC will respond to the court's remand. If the FERC were to no longer allow limited partnerships to include income tax allowance in their cost of service, our cost of service would be reduced, which could ultimately impact our tariff rates if we were ever required to adopt a cost-of-service ratemaking methodology.

Our operations are subject to extensive environmental, health, safety and other laws and regulations that impose significant requirements, costs and liabilities on us. These requirements, costs and liabilities could increase as a result of new laws or regulations or changes in the interpretation, implementation or enforcement of existing laws and regulations. Our customers are also subject to extensive environmental, health, safety and other laws and regulations, and any new laws or regulations or changes in the interpretation, implementation or enforcement of existing laws and regulations, including laws and regulations related to hydraulic fracturing, could result in decreased demand for our services.

Our operations are subject to extensive federal, state and local laws and regulations relating to the protection or preservation of the environment, natural resources and human health and safety, including but not limited to the CAA, the RCRA, the Oil Pollution Act and CWA, the CERCLA, the HLPSA, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 and OSHA. Such laws and regulations affect almost all aspects of our operations and generally require us to obtain and comply with various environmental registrations, licenses, permits, credits, inspections and other approvals. We incur substantial costs to comply with these laws and regulations, and any failure to comply may expose us to civil, criminal and administrative fees, fines, penalties and interruptions in our operations that could have a material adverse impact on our results of operations, financial position and prospects. For example, if an accidental release or spill of petroleum products, chemicals or other hazardous substances occurs at or from our pipelines, storage or other facilities, we may experience significant operational disruptions and we may have to pay a significant amount to remediate the release or spill, pay government penalties, address natural resource damages, compensate for human exposure or property damage, install costly pollution control equipment or undertake a combination of these and other measures. The resulting costs and liabilities could materially adversely affect our results of operations, financial position or cash flows. In addition, emission controls required under the CAA and other similar federal, state and provincial laws could require significant capital expenditures at our facilities.

Liability under such laws and regulations may be incurred without regard to fault. Private parties, including the owners of properties through which our pipelines pass, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with such laws and regulations or for personal injury or property damage. Our insurance may not cover all environmental risks and costs and may not provide sufficient coverage in the event an environmental claim is made against us. In addition, our insurance may not cover us for fines and penalties levied against us by governmental agencies for releases that result in environmental damages.

Our assets have been used for many years to transport, store or distribute petroleum products and ammonia. Over time our operations, or operations by our predecessors or third parties not under our control, may have resulted in the disposal or release of hydrocarbons or solid wastes at or from these terminal properties and along such pipeline rights-of-way. In addition, some of our terminals and pipelines are located on or near current or former refining and terminal sites, and there is a risk that contamination is present on those sites. We may be subject to strict, joint and several liability under a number of these environmental laws and regulations for such disposal and releases of hydrocarbons or solid wastes or the existence of contamination, even in circumstances where such activities or conditions were caused by third parties not under our control or were otherwise lawful at the time they occurred.

The laws and regulations that affect our operations, and the enforcement thereof, have become increasingly stringent over time. We cannot ensure that these laws and regulations will not be further revised or that new laws or regulations will not be adopted or become applicable to us. There can be no assurance as to the amount or timing of future expenditures to comply with laws and regulations, including expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We also face risks from political activists and protestors, who may attempt to delay pipeline construction through protests and other means, as has recently occurred in North Dakota in relation to DAPL. In addition to increasing our costs or liabilities, legal or regulatory changes or changes in the cost or availability of permits or related credits, where applicable, could also impact our ability to develop new projects. For example, changes that affect permitting or siting processes or the use of eminent domain could prevent or delay our ability to construct new pipelines or storage tanks. Revised or additional regulations that result in increased compliance costs or additional operating restrictions or liabilities could have a material adverse effect on our business, financial position, results of operations and prospects.

The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 increased penalties for safety violations, established additional safety requirements for newly-constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. PHMSA has also published notices and advanced notices of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements, and recently finalized revisions to its hazardous liquid pipeline safety regulations in January 2017. It is possible that new legislation and more stringent regulations could be adopted to enhance pipeline safety. Compliance with such legislative and regulatory changes could increase our compliance costs and have a material adverse effect on our results of operations.

Our customers are also subject to extensive laws and regulations that affect their businesses, and new laws or regulations could materially adversely affect their businesses or prospects. For example, several of our most significant customers are refineries whose businesses could be significantly impacted by changes in environmental or health-related laws or regulations. In addition, we have made and continue to make significant investments in crude oil and condensate storage and transportation projects that serve customers who largely depend on production techniques, such as hydraulic fracturing, that are currently being scrutinized by some federal and state authorities and have encountered political opposition that could result in increased regulatory costs or delays. For example, recent referendums proposed in the state of Colorado, from where most of the volume on our Saddlehorn joint venture originates, sought to restrict hydraulic fracking in that state. While these referendums failed to receive sufficient support to get on the ballot, we are unable to predict the ultimate outcome of any such political activity in the future. Any changes in laws or regulations, or in the interpretation, implementation or enforcement of existing laws and regulations, that impose significant costs or liabilities on our customers, or that result in delays or cancellations of their projects, could reduce their demand for our services and materially adversely affect our results of operations, financial position or cash flows and our ability to pay cash distributions.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the products that we transport, store or distribute.

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, in

September 2009, the EPA issued a final rule requiring the monitoring and reporting of greenhouse gas emissions from certain large greenhouse gas emissions sources. This reporting rule was expanded in November 2010 to include petroleum facilities. We have adopted procedures for required reporting.

Congress has from time to time considered legislation to reduce emissions of greenhouse gases. In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce greenhouse gas emissions. The agreement became effective in November 2016 after more than 70 countries, including the United States, ratified or otherwise indicated their intent to be bound by the agreement. To the extent the United States and other countries impose other climate change regulations on the oil industry, it could have an adverse direct or indirect effect on our business.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations that limit or regulate emissions of greenhouse gases could adversely affect demand for the products that we transport, store and distribute and, depending on the particular program adopted, could 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 greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas 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, increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

Our butane blending activities subject us to federal regulations that govern renewable fuel requirements in the United States.

The Energy Independence and Security Act of 2007 expanded the required use of renewable fuels in the United States. Each year, the EPA establishes an RVO requirement for refiners and fuel manufacturers based on overall quotas established by the federal government. By virtue of our butane blending activity and resulting gasoline production, we are an obligated party and receive an annual RVO from the EPA. In lieu of blending renewable fuels (such as ethanol and biodiesel), we must purchase renewable energy credits, called RINs, to meet this obligation. RINs are generated when a gallon of biofuel such as ethanol or biodiesel is produced. RINs may be separated when the biofuel is blended into gasoline or diesel, at which point the RIN is available for use in compliance or is available for sale on the open market. Increases in the cost or decreases in the availability of RINs could have an adverse impact on our results of operations, cash flows and cash distributions.

Our business is subject to federal, state and local laws and regulations that govern the product quality specifications of the petroleum products that we store, transport or sell.

Petroleum products that we store and transport are sold by our customers for consumption into the public market. Various federal, state and local agencies have the authority to prescribe specific product quality specifications for commodities sold into the public market. Changes in product quality specifications or blending requirements could reduce our throughput volume, require us to incur additional handling costs or require capital expenditures. For instance, different product specifications for different markets impact the fungibility of the products in our system and could require the construction of additional storage. If we are unable to recover these costs through increased revenue, our cash flows and ability to pay cash distributions could be materially adversely affected.

In addition, changes in the product quality of the products we receive on our refined products pipeline, or changes in the product specifications in the markets we serve, could reduce or eliminate our ability to blend products, which would result in a reduction of our revenue and operating profit from blending activities. Any such reduction of our revenue or operating profit could have a material adverse effect on our results of operations, financial position, cash flows and ability to pay cash distributions.

Our business could be affected adversely by union disputes and strikes or work stoppages by our unionized employees.

As of December 31, 2016, approximately 15% of our workforce was covered by two collective bargaining agreements with different terms and dates of expirations. There can be no assurances that we will not experience a work stoppage in the future as a result of disagreements with these labor unions. A prolonged work stoppage could have a material adverse effect on our business activities, results of operations and cash flows.

Skills and institutional knowledge possessed by our current employees may be difficult to retain, and our growth strategy depends in part on our ability to recruit and retain employees with appropriate skills.

A significant percentage of our employees, including much of our management team, will become eligible for retirement over the next several years. Many of those employees have skills and institutional knowledge that have been developed over many years of service. As these employees reach retirement age, we may be unable to replace them with employees with comparable knowledge and experience, and we may be unable to transfer their knowledge successfully to new qualified employees. In addition, our growth strategy requires that we hire additional employees with the skills required to develop and operate our assets. For example, our crude oil segment has experienced rapid growth in recent years, and we continue to make significant investments in each of our operating segments. If we are unable to transfer knowledge successfully to new employees or are otherwise unable to recruit and retain sufficiently talented personnel, we could experience increased costs, our growth strategy could be slowed or we could encounter other difficulties in running our business efficiently.

An impairment of long-lived assets, investments in non-controlled entities or goodwill could reduce our earnings and negatively impact the value of our limited partner units.

At December 31, 2016, we had $5.3 billion of net property, plant and equipment, $0.9 billion of investments in non-controlled entities and $53.3 million of goodwill. U.S. GAAP requires us to periodically test long-lived assets, investments in non-controlled entities and goodwill for impairment. If we were to determine that any of our long-lived assets, investments in non-controlled entities or goodwill were impaired, we would be required to take an immediate charge to earnings with a corresponding reduction of partners' equity. Such charges could be material to our results of operations and could adversely impact the value of our limited partner units.

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

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

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. Our unitholders could be liable for any and all of our obligations as if they were a general partner if a court or government agency were to determine that:

- We were conducting business in a state but had not complied with that particular state's partnership statute; or

- Our unitholders' rights to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Our general partner's board of directors' absolute discretion in determining our level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our general partner's board of directors to deduct from available cash the amount of any cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, the partnership agreement permits our general partner's board of directors to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable laws or agreements to which we are a party or to provide funds for future distributions to partners. Any such cash reserves will reduce the amount of cash currently available for distribution to our unitholders.

Our partnership agreement replaces our general partner's fiduciary duties to holders of our limited partner units with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our partnership agreement permits our general partner to make a number of decisions in its sole discretion, free of any duties to us and holders of our limited partner units other than the implied contractual covenant of good faith and fair dealing. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us or our limited partners. By owning a limited partner unit, a holder is treated as having consented to the provisions in our partnership agreement.

Our partnership agreement restricts the remedies available to holders of our limited partner units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to holders of our limited partner units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement:

- provides that whenever our general partner is permitted or required to make a decision, in its capacity as our general partner, our general partner is permitted or required to make such a decision in good faith and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation;

- provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission if our general partner or its officers and directors, as the case may be, acted in good faith; and

- provides that, in the absence of bad faith, our general partner will not be in breach of its obligations under our partnership agreement or its fiduciary duties to us or our limited partners if a transaction with an affiliate or the resolution of a conflict of interest is approved in accordance with, or otherwise meets the standards set forth in, our partnership agreement.

Limited partner units held by persons who are not citizenship-eligible may be subject to redemption.

Our partnership agreement contains provisions that apply if we determine that the nationality, citizenship or other related status of a holder of our limited partnership units creates a substantial risk of cancellation or forfeiture of any property in which we have an interest. If a holder of our limited partner units is not a person who meets the requirements to be a citizenship-eligible holder, which generally includes U.S. entities and individuals who are U.S. citizens, and, therefore, creates a risk to the partnership, the holder may have its limited partner units redeemed by us. In addition, if a holder of our limited partner units does not meet the requirements to be a citizenship-eligible holder, such holder will not be entitled to voting rights and may not receive distributions in kind upon our liquidation.

Tax Risks to Limited Partner Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, or otherwise subject us to entity-level taxation, it would reduce the amount of cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in our limited partner units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Payments to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced over time. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our limited partner units.

The tax treatment of our structure could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. From time to time the U.S. government considers substantive changes to the existing federal income tax laws that affect publicly traded partnerships. For example, both the Trump administration and current congressional leadership have expressed intentions to enact significant changes to existing U.S. tax laws. We are unable to predict whether any such changes or any other proposals will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact a unitholder's investment in our limited partner units.

At the state level, changes in current state law may subject us to additional entity-level taxation by individual states. Due to state budget deficits and for other reasons, several states frequently evaluate ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may materially reduce the cash available for distribution to our unitholders.

In January 2017, the Treasury Department and the IRS issued final regulations related to the determination of qualifying income for publicly traded partnerships. These regulations should have no material impact on us and should not impact our classification as a partnership for U.S. federal income tax purposes.

If the IRS contests the federal income tax positions we take, the market for our limited partner units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

The IRS has made no determination as to our status as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our limited partner units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders as the costs will reduce our cash available for distribution.

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

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, our unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on disposition of our limited partner units could be more or less than expected.

If our unitholders sell their limited partner units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those limited partner units. Prior distributions to our unitholders in excess of the total net taxable income they were allocated for a limited partner unit, which decreased their tax basis in that limited partner unit, will, in effect, become taxable income to our unitholders if the limited partner unit is sold at a price greater than their tax basis in that limited partner unit, even if the price they receive is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder’s share of nonrecourse liabilities, if our unitholders sell their limited partner units, they may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities and foreign persons face unique tax issues from owning our limited partner units that may result in adverse tax consequences to them.

Investment in limited partner units by tax-exempt entities, such as employee benefit plans, individual retirement accounts (known as IRAs) and foreign persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to foreign persons will be reduced by withholding taxes at the highest applicable effective tax rate, and foreign persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. Tax-exempt entities or foreign persons should consult their tax advisor before investing in our limited partner units.

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

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

The IRS may challenge aspects of our proration method, and, if successful, we would be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our limited partner units each month based upon the ownership of our limited partner units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Department of Treasury and the IRS issued Treasury Regulations that permit publicly traded partnerships to use a monthly simplifying convention that is similar to ours, but they do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to successfully challenge this method, we could be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose limited partner units are loaned to a "short seller" to cover a short sale of limited partner units may be considered to have disposed of those limited partner units. If so, he would no longer be treated for tax purposes as a partner with respect to those limited partner units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose limited partner units are loaned to a "short seller" to cover a short sale of limited partner units may be considered to have disposed of the loaned limited partner units, the unitholder may no longer be treated for tax purposes as a partner with respect to those limited partner units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those limited partner units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those limited partner units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their limited partner units.

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

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

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

The sale or exchange of 50% or more of our capital and profits interests during any 12-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit are counted only once. Our technical termination would not affect our classification as a partnership for federal income tax purposes, but could, among other things, result in the closing of our taxable year for all unitholders, which could result in our filing two tax returns for one fiscal year, and in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year results in more than 12 months of our taxable income or loss being includable in the unitholder's taxable income for the year of termination.

Our unitholders may be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our limited partner units.

In addition to federal income taxes, our unitholders may be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own assets and conduct business in 25 states, most of which impose a personal income tax. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Generally, we expect to elect to have our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, but there can be no assurance that such election will be made, or applicable, in all circumstances. If we are unable to have our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, our current unitholders may bear some or all of the economic burden resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced.

The current administration has delayed the implementation of certain regulations and signaled through formal and informal means that certain other income tax related regulations could be changed. The partnership audit regulations could be subject to revision, withdrawal or material adjustment, but the specifics of any such action cannot be reasonably predicted at this time.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

See Item 1(c) for a description of the locations and general character of our material properties.

Item 3. ***Legal Proceedings***

Anhydrous Ammonia Event. On October 17, 2016, we experienced a release of anhydrous ammonia on our ammonia pipeline system near Tekamah, Nebraska. The release resulted in a fatality and other possible injuries. The National Transportation Safety Board is investigating the event. We are currently unable to estimate the full impact of this event. However, we believe the impact on our financial position and results of operations is not likely to be material as defined by the SEC.

Condensate Splitter Litigation. On January 27, 2017, our subsidiary, Magellan Processing, L.P., filed suit against Trafigura Trading LLC ("Trafigura"), in the District Court of Harris County, Texas, alleging breach of contract under the tolling agreement and revenue commitment agreement executed by the parties in connection with the condensate splitter we have constructed at our Corpus Christi terminal. As a result of Trafigura's wrongful termination of these agreements, Magellan Processing, L.P. is seeking full contractual damages, costs of the action and attorneys' fees, pre- and post-judgment interest and all other relief, in law or equity, to which Magellan Processing, L.P. is entitled.

Settlement of Clean Water Act Claims. In July 2011, we received an information request from the EPA pursuant to Section 308 of the Clean Water Act regarding a pipeline release near Texas City, Texas in February 2011 (the "Texas Release"). In April 2012, we received a similar information request from the EPA pursuant to Section 308 of the Clean Water Act regarding a pipeline release near Nemaha, Nebraska in December 2011 (the "Nebraska Release"). In October 2015, we received a letter from the U.S. Department of Justice ("DOJ Letter") stating that the Clean Water Act claims arising out of the Texas Release, the Nebraska Release and a pipeline release near El Dorado, Kansas in May 2015 had all been referred to the U.S. Department of Justice for enforcement. In January 2017, we agreed to settle these enforcement claims for payment of $2 million and certain related injunctive relief regarding ongoing remediation efforts and future training and safety matters.

U.S. Oil Recovery, EPA ID No.: TXN000607093 Superfund Site. We have liability at the U.S. Oil Recovery Superfund Site in Pasadena, Texas as a potential responsible party ("PRP") under Section 107(a) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended ("CERCLA"). As a result of the EPA's Administrative Settlement Agreement and Order on Consent for Removal Action, filed August 25, 2011, EPA Region 6, CERCLA Docket No. 06-10-11, we voluntarily entered into the PRP group responsible for the site investigation, stabilization and subsequent site cleanup. We have paid $15,000 associated with the assessment phase. Until this assessment phase has been completed, we cannot reasonably estimate our proportionate share of the remediation costs associated with this site. While the results cannot be reasonably estimated, we believe the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

Lake Calumet Cluster Site, EPA ID No.: ILD000716852 Superfund Site. We have liability at the Lake Calumet Cluster Superfund Site in Chicago, Illinois as a PRP under Sections 107(a) and 113(f)(1) of CERCLA. As a result of the EPA's Administrative Settlement Agreement and Order for Remedial Investigation/Feasibility Study of June 2013, we voluntarily entered into the PRP group responsible for the investigation, cleanup and installation of an appropriate clay cap over the site. We have paid $8,000 associated with the Remedial Investigation/Feasibility Study and cleanup costs to date. Our projected portion of the estimated cap installation is $55,000. While the results cannot be predicted with certainty, we believe the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

We are a party to various other claims, legal actions and complaints arising in the ordinary course of business. 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 future results of operations, financial position or cash flows.

Item 4. ***Mine Safety Disclosures***

Not applicable.

PART II

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

Our limited partner units representing limited partnership interests are listed and traded on the New York Stock Exchange under the ticker symbol "MMP." At the close of business on February 14, 2017, we had 228,024,556 limited partner units outstanding that were owned by approximately 179,000 record holders and beneficial owners (held in street name).

The year-end closing sales price of our limited partner units was $67.92 on December 31, 2015 and $75.63 on December 30, 2016. The high and low trading prices for our limited partner units and distribution paid per unit by quarter for 2015 and 2016 were as follows:

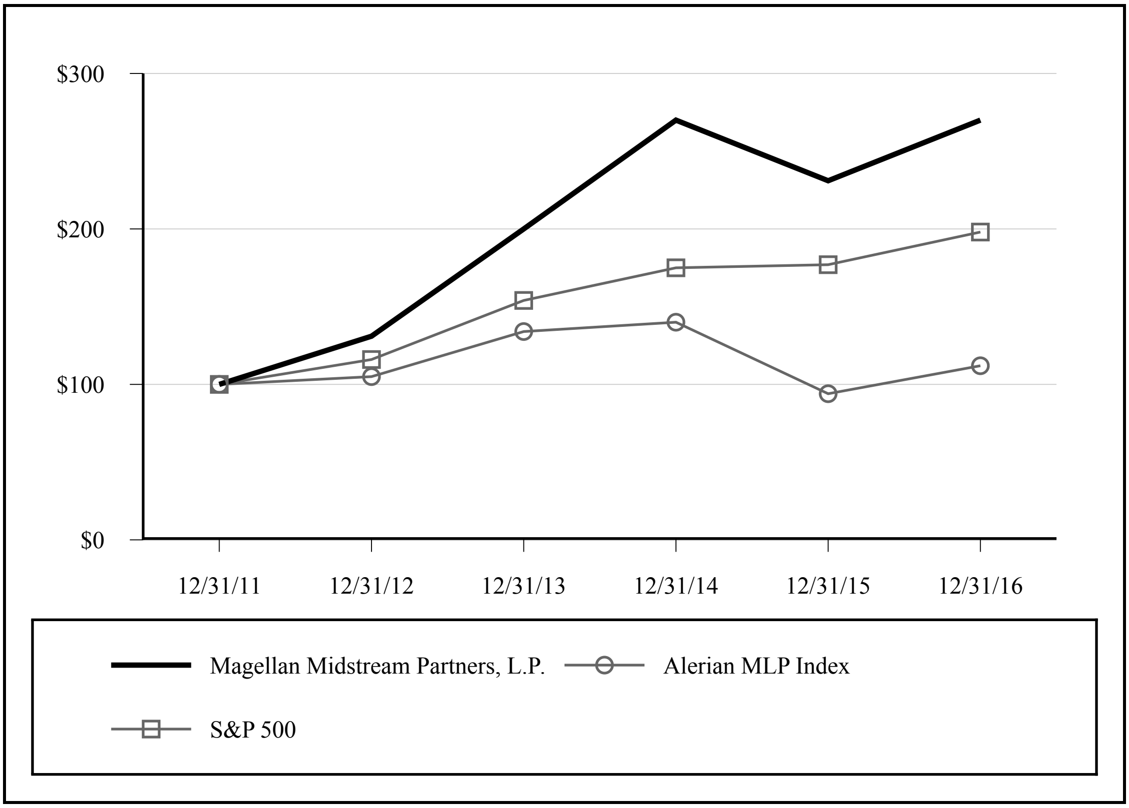
	2015			2016		
Quarter	**High**	**Low**	**Distribution***	**High**	**Low**	**Distribution***
1st	$ 85.85	$ 72.90	$ 0.7175	$ 72.00	$ 55.25	$ 0.8025
2nd	$ 85.49	$ 73.36	$ 0.7400	$ 77.45	$ 63.40	$ 0.8200
3rd	$ 76.04	$ 55.05	$ 0.7625	$ 77.10	$ 67.34	$ 0.8375
4th	$ 70.26	$ 54.51	$ 0.7850	$ 75.92	$ 64.25	$ 0.8550

* Represents declared distributions associated with each respective quarter. Distributions were declared and paid within 45 days following the close of each quarter.

We must distribute all of our available cash, as defined in our partnership agreement, at the end of each quarter, less reserves established by our general partner's board of directors. We currently pay quarterly cash distributions of $0.855 per limited partner unit. In general, we intend to increase our cash distribution; however, we cannot guarantee that future distributions will increase or continue at current levels.

Unitholder Return Performance Presentation

The following graph compares the total unitholder return performance of our limited partner units with the performance of (i) the Standard & Poor's 500 Stock Index ("S&P 500") and (ii) the Alerian MLP index, which is a composite of the most prominent energy master limited partnerships that provides investors with a comprehensive benchmark for this asset class. The graph assumes that $100 was invested in our limited partner units and each comparison index beginning on December 31, 2011 and that all distributions or dividends were reinvested on a quarterly basis.



	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016
Magellan Midstream Partners, L.P.	$100	$131	$200	$270	$231	$270
Alerian MLP Index	$100	$105	$134	$140	$94	$112
S&P 500	$100	$116	$154	$175	$177	$198

The information provided in this section is being furnished to and not filed with the SEC. As such, this information is neither subject to Regulation 14A or 14C nor to the liabilities of Section 18 of the Exchange Act.

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* of this report. Additionally, Note 2 – *Summary of Significant Accounting Policies* under Item 8. *Financial Statements and Supplementary Data* of this report provides 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 limited partners. Management uses DCF to determine the amount of cash that our operations generated that is available for distribution to our limited partners 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 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. We compute the components of operating margin and Adjusted EBITDA using amounts that are determined in accordance with GAAP. 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 16 – *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 an important measure of the economic performance of our core operations, and we believe that investors benefit from having access to the same financial measures utilized by management. Operating profit, alternatively, includes depreciation and amortization expense and general and administrative ("G&A") expense that management does not consider 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 an entity.

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,				
	2012	2013	2014	2015	2016
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenue	$ 1,016,166	$ 1,188,452	$ 1,459,267	$ 1,544,746	$ 1,591,119
Product sales revenue	799,382	744,669	878,974	629,836	599,602
Affiliate management fee revenue	1,948	14,609	22,111	13,871	14,689
Total revenue	1,817,496	1,947,730	2,360,352	2,188,453	2,205,410
Operating expenses	373,876	396,194	500,901	525,902	529,759
Cost of product sales	657,108	578,029	594,585	447,273	493,338
Earnings of non-controlled entities	(2,961)	(6,275)	(19,394)	(66,483)	(78,696)
Operating margin	789,473	979,782	1,284,260	1,281,761	1,261,009
Depreciation and amortization expense	128,012	142,230	161,741	166,812	178,142
G&A expense	109,403	132,496	148,288	151,329	147,815
Operating profit	552,058	705,056	974,231	963,620	935,052
Interest expense, net	113,766	118,206	121,519	143,177	165,410
Gain on exchange of interest in non-controlled entity	—	—	—	—	(28,144)
Other expense (income)[(a)]	—	—	8,573	(1,015)	(8,203)
Income before provision for income taxes	438,292	586,850	844,139	821,458	805,989
Provision for income taxes	2,622	4,613	4,620	2,336	3,218
Net income	$ 435,670	$ 582,237	$ 839,519	$ 819,122	$ 802,771
Basic net income per limited partner unit	$ 1.92	$ 2.57	$ 3.69	$ 3.60	$ 3.52
Diluted net income per limited partner unit	$ 1.92	$ 2.56	$ 3.69	$ 3.59	$ 3.52
Balance Sheet Data:					
Working capital (deficit)[(b)]	$ 307,658	$ (241,543)	$ (133,488)	$ (374,218)	$ (111,262)
Total assets	$ 4,404,987	$ 4,803,307	$ 5,501,409	$ 6,041,567	$ 6,772,073
Long-term debt, net	$ 2,378,328	$ 2,417,811	$ 2,967,019	$ 3,189,287	$ 4,087,192
Owners' equity	$ 1,515,702	$ 1,647,442	$ 1,868,233	$ 2,021,736	$ 2,092,105
Cash Distribution Data:					
Cash distributions declared per unit[(c)]	$ 1.88	$ 2.18	$ 2.62	$ 3.01	$ 3.32
Cash distributions paid per unit[(c)]	$ 1.78	$ 2.10	$ 2.51	$ 2.92	$ 3.25

	Year Ended December 31,				
	2012	2013	2014	2015	2016
	(in thousands, except operating statistics)				
Other Data:					
Operating margin:					
Refined products	$ 592,828	$ 693,985	$ 870,205	$ 777,021	$ 722,880
Crude oil	91,367	176,420	295,830	381,365	408,093
Marine storage	102,323	106,198	114,712	119,524	125,081
Allocated partnership depreciation costs(d)	2,955	3,179	3,513	3,851	4,955
Operating margin	$ 789,473	$ 979,782	$ 1,284,260	$ 1,281,761	$ 1,261,009
Adjusted EBITDA and distributable cash flow:					
Net income	$ 435,670	$ 582,237	$ 839,519	$ 819,122	$ 802,771
Interest expense, net(e)	113,766	118,206	121,519	143,177	165,410
Depreciation and amortization	128,012	142,230	161,741	166,812	178,142
Equity-based incentive compensation expense(f)	8,038	11,823	12,471	6,461	4,982
Loss on sale and retirement of assets	12,622	7,835	7,223	7,871	11,190
Gain on exchange of interest in non-controlled entity(h)	—	—	—	—	(28,144)
Commodity-related adjustments(g)	12,894	(339)	(56,288)	13,988	64,257
Cash distributions received from non-controlled entities in excess of (less than) earnings for the period	4,850	(409)	(8,724)	14,572	9,293
Other(i)	—	—	—	—	5,341
Adjusted EBITDA	715,852	861,583	1,077,461	1,172,003	1,213,242
Interest expense, net, excluding debt issuance cost amortization(e)	(111,679)	(115,782)	(119,186)	(140,464)	(162,251)
Maintenance capital(j)	(64,396)	(76,081)	(77,806)	(88,685)	(103,507)
Distributable cash flow	$ 539,777	$ 669,720	$ 880,469	$ 942,854	$ 947,484
Operating Statistics:					
Refined products:					
Transportation revenue per barrel shipped	$ 1.230	$ 1.313	$ 1.399	$ 1.439	$ 1.473
Volume shipped (million barrels):					
Gasoline	223.7	239.7	256.1	268.1	275.4
Distillates	136.7	146.5	163.1	152.5	150.2
Aviation fuel	21.5	21.1	23.0	21.2	25.7
Liquefied petroleum gases	8.5	7.8	9.9	9.7	10.4
Total volume shipped	390.4	415.1	452.1	451.5	461.7
Crude oil:(k)					
Magellan 100%-owned assets:					
Transportation revenue per barrel shipped	$ 0.305	$ 0.880	$ 1.192	$ 1.118	$ 1.321
Volume shipped (million barrels)	72.0	113.2	185.5	209.9	187.0
Crude oil terminal average utilization (million barrels per month)	12.6	12.3	12.2	13.1	15.0
Select joint venture pipelines:					
BridgeTex - volume shipped (million barrels)(l)	—	—	18.3	75.2	79.0
Saddlehorn - volume shipped (million barrels)(m)	—	—	—	—	5.2
Marine storage:					
Marine terminal average utilization (million barrels per month)	23.8	23.0	22.9	24.0	23.8

(a) Other expense (income) includes the non-cash impact of the change in the differential between the current spot price and forward price on fair value hedges associated with our tank bottom assets. Additionally, other income for 2016 includes a break-up fee related to a potential acquisition.
(b) Working capital deficit at December 31, 2013 and December 31, 2015 included the current portion of long-term debt of approximately $250 million.
(c) Cash distributions declared were determined based on the distributable cash flow 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.
(d) 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.
(e) For the purpose of calculating DCF, we have excluded debt issuance cost amortization from interest expense.
(f) Equity-based incentive compensation expense excludes the tax withholdings on settlement of equity-based incentive awards, which were paid in cash.
(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) In February 2016, we transferred our 50% membership interest in Osage to an affiliate of HollyFrontier Corporation ("HFC"). In conjunction with this transaction, we entered into several commercial agreements with affiliates of HFC, which were recorded as intangible assets and other receivables on our consolidated balance sheets. We recorded a $28.1 million non-cash gain in relation to this transaction.
(i) Other adjustments in 2016 include certain payments received from HFC in conjunction with the transfer of our 50% membership interest in Osage in February 2016. HFC agreed to make certain payments to us until HFC completes a connection to our El Paso terminal. These payments replace distributions we would have received had the Osage transaction not occurred and are, therefore, included in our calculation of DCF. See *Note 4 – Investments in Non-Controlled Entities* in *Item 8. Financial Statements and Supplementary Data* of this report for further information about this transaction.
(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) Before we converted our Longhorn pipeline to crude oil service in 2013, all of the volumes on our crude oil pipelines traveled short distances, and we charged a significantly lower tariff rate for such shipments than for the rest of our pipeline systems.
(l) These volumes reflect the total shipments for the BridgeTex pipeline, which is owned 50% by us and began operations in September 2014.
(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

We are a publicly traded limited partnership principally engaged in the transportation, storage and distribution of petroleum products. Our three operating segments including the assets of our joint ventures include:

- our refined products segment, comprised of our 9,700-mile refined products pipeline system with 53 terminals as well as 26 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;
- our crude oil segment, comprised of approximately 2,200 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 26 million barrels, of which 16 million are used for contract storage; and
- our marine storage segment, consisting of five marine terminals located along coastal waterways with an aggregate storage capacity of approximately 26 million barrels.

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes included in this annual report on Form 10-K for the year ended December 31, 2016.

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

Overview

We are a key component of our nation's energy infrastructure and provide essential transportation, distribution and storage services for our nation. We own the longest refined petroleum products pipeline system in the country with access to nearly 50% of the nation's refinery capacity, allowing us to transport gasoline and diesel fuel throughout the central region of the United States. During 2016, we extended the reach of our pipeline system to deliver petroleum products to Little Rock, Arkansas, providing this market with new access to Mid-Continent and Gulf Coast refinery production via our extensive pipeline system. In addition, we are further connecting this system to a third-party pipeline to add West Memphis as yet another delivery option for our customers later this year. Industry feedback has been positive for the long-term strategic value of these new pipeline extensions, and we continue to work with our customers to further expand our network into new markets.

Our crude oil segment continues to grow and is an important component of the energy value chain to deliver domestic crude oil production to strategic locations such as Cushing, Oklahoma and the Houston Gulf Coast region. One of our largest construction projects, the Saddlehorn pipeline, became operational during the third quarter of 2016 to deliver crude oil from the DJ Basin in Colorado to the Cushing storage hub, where we are one of the largest providers of storage. We are a 40% owner of Saddlehorn, alongside other key industry players, with commitments from the largest producers in that region.

The Longhorn and BridgeTex pipelines benefit from solid demand and are supported by take-or-pay agreements to transport crude oil from the Permian Basin in West Texas to our East Houston terminal. From there, we can further distribute product via our Houston distribution system, a comprehensive pipeline network with connectivity to all the refineries in the Houston and Texas City region.

Many in the industry believe that more crude oil pipeline capacity will be needed to meet growing Permian Basin production in the coming years. We are well-situated to accommodate incremental crude oil production volume and recently announced plans to expand the BridgeTex pipeline from 300,000 to 400,000 barrels per day so that we are adequately prepared to meet this opportunity. This expansion is extremely cost effective and will be available in the second quarter of 2017.

Our marine storage terminals are located along coastal waterways, with our most prominent presence in the Houston Gulf Coast region. U.S. Gulf Coast refiners are some of the most competitive refineries in the world and have direct access to growing U.S. crude oil production. As a result, demand is growing for storage facilities and dock capacity for refined products exports. This has led to high utilization of our marine facilities, and increased customer activity has prompted us to initiate construction of a fifth dock at our largest facility in Galena Park, Texas, which is located along the Houston Ship Channel.

Growth Projects

We spent a record $736 million on organic growth construction projects during 2016, and we continue to find attractive opportunities to further grow our business. Based on the projects currently under construction, we expect to spend an additional $900 million over the next two years to complete the projects now in progress. This capital spending includes such large projects as our new dock at Galena Park as well as construction of our new Pasadena refined products marine terminal.

We announced plans to construct a new marine terminal at Pasadena, Texas to handle refined products. We are initially building a dock and one million barrels of storage, backed by a long-term customer commitment. Our new Pasadena terminal is expected to be operational in early 2019. Based on the size of the land for this new facility, we have the capability to build an incremental nine million barrels of storage at this site and are in discussions with other customers interested in supporting further investment.

We also have announced plans to increase the scale of our Seabrook joint venture, which represents a key asset for our crude oil marine strategy. The first phase of this joint venture is scheduled to come online in the second quarter of 2017 and is backed by a long-term throughput agreement from a Gulf Coast refiner.

The recently-announced second phase of Seabrook represents construction of 1.7 million barrels of storage and connectivity to our Houston distribution system, providing attractive optionality for our long-haul crude oil pipeline and other customers to access this new facility for crude oil exports once operational in mid-2018. In addition to our further investment in Seabrook, we are separately investing in a new pipeline within our Houston distribution system to ensure we are prepared to handle incremental crude oil volume destined for the Houston Gulf Coast area.

We are continually exploring new opportunities across all of our business segments that are complementary to our existing asset portfolio, primarily focusing on fee-based activities to serve our customers' needs. Our potential project list continues to exceed well over $500 million with a variety of opportunities for each of our operating segments.

We also remain active in evaluating acquisition opportunities. We have specifically communicated our desire to extend our crude oil value chain to include gathering assets and other value-added activities that could help direct barrels to our long-haul crude oil pipelines in the Permian Basin.

Recent Developments

Cash Distribution. In January 2017, the board of directors of our general partner declared a quarterly cash distribution of $0.855 per unit for the period of October 1, 2016 through December 31, 2016. This quarterly cash distribution was paid on February 14, 2017 to unitholders of record on February 3, 2017. The total distribution paid on 228.0 million limited partner units outstanding was $195.0 million.

Corpus Christi Splitter. Our Corpus Christi condensate splitter is mechanically complete, and the unit has been operating and generating products meeting market specifications. However, the sole customer, an affiliate of Trafigura, AG, gave notice to terminate its contract in January 2017. We believe this notice was in breach of our agreement, and we have initiated legal action to seek all available remedies. We have initiated discussions with multiple potential customers regarding the future use of the splitter.

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 tables, 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 tables. Operating profit includes expense items, such as depreciation and amortization expense and general and administrative ("G&A") expenses, 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 these tables. Product margin is a non-GAAP measure; however, its components of product sales and cost of product sales are determined in accordance with GAAP. Our butane blending, fractionation 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, 2015 Compared to Year Ended December 31, 2016

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2015	**2016**	**$ Change**	**% Change**
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenue:				
Refined products	$ 974.5	$ 1,002.4	$ 27.9	3 %
Crude oil	394.1	407.8	13.7	3 %
Marine storage	176.1	181.7	5.6	3 %
Intersegment eliminations	—	(0.8)	(0.8)	n/a
Total transportation and terminals revenue	1,544.7	1,591.1	46.4	3 %
Affiliate management fee revenue	13.9	14.7	0.8	6 %
Operating expenses:				
Refined products	377.8	381.1	(3.3)	(1)%
Crude oil	89.5	88.8	0.7	1 %
Marine storage	62.5	65.7	(3.2)	(5)%
Intersegment eliminations	(3.9)	(5.8)	1.9	49 %
Total operating expenses	525.9	529.8	(3.9)	(1)%
Product margin:				
Product sales	629.8	599.6	(30.2)	(5)%
Cost of product sales	447.3	493.3	(46.0)	(10)%
Product margin	182.5	106.3	(76.2)	(42)%
Earnings of non-controlled entities	66.5	78.7	12.2	18 %
Operating margin	1,281.7	1,261.0	(20.7)	(2)%
Depreciation and amortization expense	166.8	178.1	(11.3)	(7)%
G&A expense	151.3	147.8	3.5	2 %
Operating profit	963.6	935.1	(28.5)	(3)%
Interest expense (net of interest income and interest capitalized)	143.2	165.4	(22.2)	(16)%
Gain on exchange of interest in non-controlled entity	—	(28.1)	28.1	n/a
Other expense (income)	(1.0)	(8.2)	7.2	(720)%
Income before provision for income taxes	821.4	806.0	(15.4)	(2)%
Provision for income taxes	2.3	3.2	(0.9)	(39)%
Net income	$ 819.1	$ 802.8	$ (16.3)	(2)%
Operating Statistics				
Refined products:				
Transportation revenue per barrel shipped	$ 1.439	$ 1.473		
Volume shipped (million barrels):				
Gasoline	268.1	275.4		
Distillates	152.5	150.2		
Aviation fuel	21.2	25.7		
Liquefied petroleum gases	9.7	10.4		
Total volume shipped	451.5	461.7		
Crude oil:				
Magellan 100%-owned assets:				
Transportation revenue per barrel shipped	$ 1.118	$ 1.321		
Volumes shipped (million barrels)	209.9	187.0		
Crude oil terminal average utilization (million barrels per month)	13.1	15.0		
Select joint venture pipelines:				
BridgeTex - volume shipped (million barrels)[a]	75.2	79.0		
Saddlehorn - volume shipped (million barrels)[b]	—	5.2		
Marine storage:				
Marine terminal average utilization (million barrels per month)	24.0	23.8		

(a) These volumes reflect the total shipments for the BridgeTex pipeline, which is owned 50% by us.

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

Transportation and terminals revenue increased by $46.4 million, resulting from:

- an increase in refined products revenue of $27.9 million. Transportation revenue was favorably impacted by the mid-year 2015 tariff rate increase of 4.6% and the mid-year 2016 increase which averaged approximately 2.0% across all of our markets. Shipments increased 2% in 2016 primarily associated with additional volumes from recent growth projects, including our Little Rock pipeline extension which commenced commercial operations in July 2016, and increased demand for gasoline and aviation fuel. Additionally, revenue from storage services along our pipeline system increased due to new customer contracts;

- an increase in crude oil revenue of $13.7 million primarily due to higher average rates, as well as new storage contracts. Overall crude oil shipments declined and average rate per barrel increased due to fewer barrels moving on our lower-priced Houston distribution system tariff structure to their ultimate destination. Instead, customers utilized space available on our capacity lease for shipments from the BridgeTex pipeline; and

- an increase in marine storage revenue of $5.6 million primarily due to higher average rates from contract renewals and escalations. Total utilization decreased slightly due in part to timing of project work to convert tanks to crude oil service at our Galena Park, Texas terminal in 2016.

Affiliate management fee revenue increased $0.8 million primarily resulting from a one-time start-up fee received from Saddlehorn, which began operations in September 2016, partially offset by lower construction management fees received from our joint ventures and lower fees from Osage Pipe Line Company, LLC (“Osage”) due to the transfer of our 50% membership interest in 2016.

Operating expenses increased $3.9 million, resulting from:

- an increase in refined products expenses of $3.3 million primarily resulting from rental costs related to a pipeline segment we began leasing in third quarter 2016 in connection with our Little Rock pipeline extension, higher asset retirements and higher environmental accruals, partially offset by lower asset integrity spending due to timing of tank maintenance work;

- a decrease in crude oil expenses of $0.7 million as lower power costs and more favorable product overages (which reduce operating expenses) were primarily offset by increased personnel costs related to incremental headcount to support the crude oil segment; and

- an increase in marine storage expenses of $3.2 million primarily attributable to higher asset integrity spending in the current year.

Product sales revenue resulted primarily from our butane blending activities, transmix fractionation and the sale of product gains from our operations. We utilize futures contracts to hedge against changes in the price of petroleum products we expect to sell in future periods, as well as to hedge against changes in the price of butane we expect to purchase. See Note 13 *–Derivative Financial Instruments* in Item 8. *Financial Statements and Supplementary Data* for a discussion of our hedging strategies and how our use of futures contracts impacts our product margin. Product margin decreased $76.2 million primarily due to lower margins from our butane blending activities as a result of lower realized sales prices and higher losses on futures contracts recognized in 2016. See *Other Items—Commodity Derivative Agreements—Impact of Commodity Derivatives on Results of Operations* below for more information about our futures contracts.

Earnings of non-controlled entities increased $12.2 million primarily attributable to increased earnings from BridgeTex due to higher shipments in 2016, as well as earnings from Saddlehorn, which began operating during third quarter 2016, and higher earnings from Double Eagle.

Depreciation and amortization expense increased $11.3 million in 2016 primarily due to recent expansion capital expenditures.

G&A expense decreased $3.5 million between periods primarily due to lower equity-based incentive compensation and lower employee bonus accruals.

Interest expense, net of interest income and interest capitalized, increased $22.2 million in 2016 primarily due to higher outstanding debt, partially offset by higher capitalized interest. Our average outstanding debt increased from $3.3 billion in 2015 to $3.9 billion in 2016 primarily due to borrowings for expansion capital expenditures. In addition, our weighted-average interest rate of 4.9% in 2016 was higher than the 4.7% rate incurred in 2015.

In 2016, we recognized a $28.1 million gain related to the transfer of our 50% membership interest in Osage. See Note 4 – *Investments in Non-Controlled Entities* in Item 8. *Financial Statements and Supplementary Data* of this report for more details regarding this transaction.

Other income increased $7.2 million due to a more favorable non-cash adjustment in the current year for the change in the differential between the current spot price and forward price on fair value hedges associated with our crude oil tank bottoms. Additionally, other income for the current period includes a break-up fee related to a potential acquisition.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2015

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2014	**2015**	**$ Change**	**% Change**
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenue:				
Refined products	$ 946.6	$ 974.5	$ 27.9	3 %
Crude oil	341.9	394.1	52.2	15 %
Marine storage	170.7	176.1	5.4	3 %
Total transportation and terminals revenue	1,459.2	1,544.7	85.5	6 %
Affiliate management fee revenue	22.1	13.9	(8.2)	(37)%
Operating expenses:				
Refined products	356.0	377.8	(21.8)	(6)%
Crude oil	83.2	89.5	(6.3)	(8)%
Marine storage	65.2	62.5	2.7	4 %
Intersegment eliminations	(3.5)	(3.9)	0.4	11 %
Total operating expenses	500.9	525.9	(25.0)	(5)%
Product margin:				
Product sales	879.0	629.8	(249.2)	(28)%
Cost of product sales	594.6	447.3	147.3	25 %
Product margin	284.4	182.5	(101.9)	(36)%
Earnings of non-controlled entities	19.4	66.5	47.1	243 %
Operating margin	1,284.2	1,281.7	(2.5)	— %
Depreciation and amortization expense	161.7	166.8	(5.1)	(3)%
G&A expense	148.3	151.3	(3.0)	(2)%
Operating profit	974.2	963.6	(10.6)	(1)%
Interest expense (net of interest income and interest capitalized)	121.5	143.2	(21.7)	(18)%
Other expense (income)	8.6	(1.0)	9.6	n/a
Income before provision for income taxes	844.1	821.4	(22.7)	(3)%
Provision for income taxes	4.6	2.3	2.3	50 %
Net income	$ 839.5	$ 819.1	$ (20.4)	(2)%
Operating Statistics				
Refined products:				
Transportation revenue per barrel shipped	$ 1.399	$ 1.439		
Volume shipped (million barrels):				
Gasoline	256.1	268.1		
Distillates	163.1	152.5		
Aviation fuel	23.0	21.2		
Liquefied petroleum gases	9.9	9.7		
Total volume shipped	452.1	451.5		
Crude oil:				
Magellan 100%-owned assets:				
Transportation revenue per barrel shipped	$ 1.192	$ 1.118		
Volumes shipped (million barrels)	185.5	209.9		
Crude oil terminal average utilization (million barrels per month)	12.2	13.1		
Select joint venture pipelines:				
BridgeTex - volume shipped (million barrels)[(a)]	18.3	75.2		
Marine storage:				
Marine terminal average utilization (million barrels per month)	22.9	24.0		

(a) These volumes reflect the total shipments for the BridgeTex pipeline, which began operations in September 2014 and is owned 50% by us.

Transportation and terminals revenue increased by $85.5 million, resulting from:

- an increase in refined products revenue of $27.9 million primarily attributable to higher transportation revenue and related ancillary fees. Higher transportation revenue was favorably impacted by higher rates, which increased due to the mid-year 2014 and 2015 tariff rate increases of 3.9% and 4.6%, respectively. Volumes were essentially the same between periods as lower distillate shipments were offset by higher gasoline demand. Distillate shipments were 7% lower due to reduced demand from drilling activities and wet agricultural conditions in the areas served by our assets, whereas gasoline shipments increased 5% resulting from refinery turnarounds that increased demand on our system and lower gasoline prices that increased overall demand for gasoline. Additionally, revenue from our independent terminals increased primarily from two terminal acquisitions, revenue from storage services along our pipeline system increased due to new customer contracts and our ammonia pipeline revenue increased due to higher rates and volumes;

- an increase in crude oil revenue of $52.2 million primarily due to revenue received in 2015 from BridgeTex to lease capacity on our Houston-area crude oil distribution system and higher crude oil deliveries on our Longhorn pipeline, partially offset by lower tender deductions received from customers. Shipments on our Longhorn pipeline averaged approximately 260,000 barrels per day in 2015, an increase of approximately 30,000 barrels per day over 2014. Additionally, terminalling revenue was higher resulting from new storage contracts and from a customer buying out of its remaining storage contract in 2015. Transportation revenue per barrel shipped was lower in 2015 due to reduced average tariffs resulting from a lower volume of spot shipments on the Longhorn pipeline system, which ship at a higher rate, and more short-haul movements on our Houston-area crude oil distribution system in 2015; and

- an increase in marine storage revenue of $5.4 million primarily due to improved storage utilization from new contracts and less storage out of service for maintenance work, as well as higher ancillary fees reflecting increased customer activities at our marine facilities. Higher average storage rates from contract renewals and escalations in 2015 were offset by a one-time favorable contract adjustment in 2014.

Affiliate management fee revenue decreased $8.2 million in 2015 due to lower construction management fees related to BridgeTex, as the pipeline became operational in September 2014.

Operating expenses increased $25.0 million, resulting from:

- an increase in refined products expenses of $21.8 million primarily resulting from higher asset integrity spending and higher personnel costs, partially offset by more favorable product overages (which reduce operating expense) and lower power costs;

- an increase in crude oil expenses of $6.3 million primarily due to higher pipeline rental fees and costs associated with having more assets in crude oil service in 2015, such as higher personnel costs and property taxes, partially offset by more favorable product overages (which reduce operating expense); and

- a decrease in marine storage expenses of $2.7 million primarily attributable to lower asset integrity costs due to timing of project work and lower property taxes due to a favorable adjustment in 2015.

Product margin decreased $101.9 million primarily due to reduced gains on futures contracts in 2015 versus 2014, partially offset by higher profits from our transmix fractionation activities resulting from lower inventory costs and higher volumes and favorable lower-of-cost-or-market ("LCM") inventory adjustments (2014 included a $39.3 million LCM inventory adjustment to our fractionation and butane blending inventories due to the significant decline in commodity prices at the end of that year, compared to a $5.0 million LCM inventory adjustment in 2015).

Earnings of non-controlled entities increased $47.1 million primarily due to our share of earnings from BridgeTex, which began operations late in 2014.

Depreciation and amortization expense increased $5.1 million in 2015 primarily due to expansion capital projects placed into service and a $1.8 million asset impairment charge recognized in 2015, partially offset by the $9.4 million acceleration of depreciation for pipeline, terminal and related assets during 2014 that we later sold.

G&A expense increased $3.0 million between periods primarily due to higher personnel costs resulting from an increase in employee headcount and higher pension and benefit costs, partially offset by lower costs associated with deferred board of director compensation and equity-based compensation resulting from a decrease in the price of our limited partner units in 2015.

Interest expense, net of interest income and interest capitalized, increased $21.7 million in 2015 primarily due to higher debt outstanding in 2015 compared to 2014 and lower capitalized interest related to BridgeTex in 2015 since BridgeTex began operations in September 2014. Our average outstanding debt increased from $2.9 billion in 2014 to $3.3 billion in 2015 primarily due to borrowings for expansion capital expenditures. Our weighted-average interest rate decreased from 4.9% in 2014 to 4.7% in 2015 due to the impact of our commercial paper borrowings and March 2015 debt issuances, which are both at lower weighted-average rates than the debt we retired in mid-2014.

Other expense (income) included $9.6 million of favorable non-cash adjustments for the change in the differential between the then-current spot price and forward price on fair value hedges associated with our crude oil tank bottoms and linefill assets.

Provision for income taxes was $2.3 million favorable due to a reduction in the franchise tax rate for the state of Texas in 2015.

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, 2014, 2015 and 2016 to net income, which is the nearest comparable GAAP financial measure, is as follows (in millions):

	Year Ended December 31,		
	2014	2015	2016
Net income	$ 839.5	$ 819.1	$ 802.8
Interest expense, net[1]	121.5	143.2	165.4
Depreciation and amortization	161.8	166.8	178.1
Equity-based incentive compensation expense[2]	12.5	6.5	5.0
Loss on sale and retirement of assets	7.2	7.9	11.2
Gain on exchange of interest in non-controlled entity[3]	—	—	(28.1)
Commodity-related adjustments:			
Derivative losses (gains) recognized in the period associated with future product transactions[5]	(87.5)	(47.8)	21.8
Derivative (losses) gains recognized in previous periods associated with product sales completed in the period[5]	(8.1)	96.1	45.2
Lower-of-cost-or-market inventory adjustments[6]	39.3	(34.3)	(2.8)
Total commodity-related adjustments	(56.3)	14.0	64.2
Cash distributions received from non-controlled entities in excess of (less than) earnings for the period	(8.7)	14.5	9.3
Other[4]	—	—	5.3
Adjusted EBITDA	1,077.5	1,172.0	1,213.2
Interest expense, net, excluding debt issuance cost amortization[1]	(119.2)	(140.5)	(162.2)
Maintenance capital[7]	(77.8)	(88.7)	(103.5)
DCF	$ 880.5	$ 942.8	$ 947.5

(1) For the purpose of calculating DCF, we have excluded debt issuance cost amortization from interest expense of $2.3 million, $2.7 million and $3.2 million for the years ended December 31, 2014, 2015 and 2016, respectively.

(2) Because we intend to satisfy vesting of unit awards under our equity-based incentive compensation program with the issuance of limited partner units, expenses related to this program generally are deemed non-cash and added back for DCF purposes. Total equity-based incentive compensation expense for the years ended December 31, 2014, 2015 and 2016 was $27.3 million, $24.3 million and $19.4 million, respectively. However, the figures above include adjustments of $14.8 million, $17.8 million and $14.4 million, respectively, for minimum statutory tax withholdings we paid in connection with our equity-based incentive compensation program.

(3) In February 2016, we transferred our 50% membership interest in Osage to an affiliate of HollyFrontier Corporation ("HFC"). In conjunction with this transaction, we entered into several commercial agreements with affiliates of HFC, which were recorded as intangible assets and other receivables on our consolidated balance sheets. We recorded a $28.1 million non-cash gain in relation to this transaction.

(4) In conjunction with the February 2016 Osage transaction, HFC agreed to make certain payments to us until HFC completes a connection to our El Paso terminal. These payments replace distributions we would have received had the Osage transaction not occurred and are, therefore, included in our calculation of DCF.

(5) Certain derivatives we use as economic hedges have not been designated as hedges for accounting purposes and the mark-to-market changes of these derivatives are recognized currently in earnings. In addition, we have designated certain derivatives we use to hedge our crude oil tank bottoms as fair value hedges and the change in the differential between the current spot price and forward price on these hedges is recognized currently in earnings. We exclude the net impact of both of these adjustments from our determination of DCF until the hedged products are physically sold. In the period in which these hedged products are physically sold, the net impact of the associated hedges is included in our determination of DCF.

(6) We add the amount of LCM adjustments on inventory and firm purchase commitments we recognize in each applicable period to determine DCF as these are non-cash charges against income. In subsequent periods when we physically sell or purchase the related products, we deduct the LCM adjustments previously recognized to determine DCF.

(7) 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 $1,107.3 million, $1,069.7 million and $964.0 million for the years ended December 31, 2014, 2015 and 2016, respectively. The $105.7 million decrease from 2015 to 2016 was due to changes in our working capital, adjustments to non-cash items and lower net income as previously described. The $37.6 million decrease from 2014 to 2015 was due to changes in our working capital and lower net income as previously described, partially offset by adjustments to non-cash items.

Investing Activities. Net cash used by investing activities for the years ended December 31, 2014, 2015 and 2016 was $830.0 million, $810.8 million and $857.4 million, respectively. During 2016, we incurred $653.5 million for capital expenditures, which included $103.5 million for maintenance capital and $550.0 million for expansion capital. Also during 2016, we contributed capital of $200.0 million in conjunction with our joint venture capital projects, which we account for as investments in non-controlled entities. During 2015, we incurred $623.3 million for capital expenditures, which included $88.7 million for maintenance capital and $534.6 million for expansion capital. Also during 2015, we acquired a refined products terminal in the Atlanta, Georgia market for $54.7 million and we contributed capital of $152.5 million in conjunction with our joint venture capital projects. During 2014, we incurred $366.4 million for capital expenditures, which included $77.8 million for maintenance capital and $288.6 million for expansion capital. Also during 2014, we contributed capital of $408.0 million in conjunction with our joint venture capital projects (primarily BridgeTex) and we acquired from a subsidiary of Oxy its ownership interest in a 40-mile crude oil pipeline in the Houston Gulf Coast area for $75.0 million.

Financing Activities. Net cash used by financing activities for the years ended December 31, 2014, 2015 and 2016 was $285.5 million, $247.3 million and $120.7 million, respectively. During 2016, we paid cash distributions of $739.2 million to our unitholders. Additionally, we received net proceeds of $1.1 billion from borrowings under long-term notes, which were used in part to repay our $250.0 million of 5.65% notes due 2016, to repay borrowings outstanding under our commercial paper program and for general partnership purposes, including expansion capital. Net commercial paper repayments during 2016 totaled $230.0 million. In connection with certain of the borrowings under long-term notes, we paid $19.3 million in settlement of associated interest rate swap agreements. Also, in February 2016, the cumulative amounts of the January 2013 equity-based incentive compensation awards were settled by issuing 350,552 limited partner units to the long-term incentive plan ("LTIP") participants, resulting in payments of associated tax withholdings of $14.4 million. During 2015, we paid cash distributions of $662.9 million to our unitholders. Additionally, we received net proceeds of $499.6 million from borrowings under long-term notes, which were used in part to repay borrowings outstanding under our commercial paper program and for general partnership purposes, including expansion capital. In connection with the borrowings under long-term notes, we paid $42.9 million in settlement of associated interest rate swap agreements. Also, in January 2015, the cumulative amounts of the January 2012 equity-based incentive compensation awards were settled by issuing 354,529 limited partner units to the LTIP participants, resulting in payments of associated tax withholdings of $17.8 million. During 2014, we paid cash distributions of $568.8 million to our unitholders. Additionally, we received net proceeds of $257.7 million from borrowings under long-term notes and $296.9 million from borrowings under our commercial paper program, which were used in part to repay our $250.0 million of 6.45% notes due 2014, to repay borrowings outstanding under our revolving credit facility and for general partnership purposes, including expansion capital. Also, in 2014, the cumulative amounts of the 2011 equity-based incentive compensation awards were settled by issuing 387,216 limited partner units to the LTIP participants, resulting in payments of associated tax withholdings of $14.8 million.

The quarterly distribution amount related to fourth quarter 2016 earnings was $0.855 per unit, which was paid in February 2017. If we are able to meet management's targeted distribution growth of 8% during 2017 and the number of outstanding limited partner units remains at 228.0 million, total cash distributions of approximately $817 million will be paid to our unitholders related to 2017 earnings. Management believes we will have sufficient distributable cash flow to fund these distributions.

Capital Requirements

Our businesses require continual investment to upgrade or enhance existing operations and to ensure compliance with safety and environmental regulations. Capital spending for our businesses consists primarily of:

- Maintenance capital expenditures. These capital expenditures include costs required to maintain equipment reliability and safety and to address environmental or 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 additional assets to grow our business and to expand or upgrade our existing facilities, which we refer to 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 2016, our maintenance capital spending was $103.5 million. For 2017, we expect to spend approximately $90.0 million on maintenance capital.

During 2016, we spent $550.0 million for expansion capital and contributed $200.0 million to our joint venture capital projects, primarily related to our investment in Saddlehorn. Based on the progress of expansion projects already underway, we expect to spend approximately $550.0 million for expansion capital during 2017, with an additional $350.0 million in 2018 to complete our current projects. See *Growth Projects* above for additional information.

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 facilities, as well as from other borrowings or issuances of debt or limited partner units (see Note 12 – *Debt* in *Item 8. Financial Statements and Supplementary Data* of this report for detail of our borrowings and debt outstanding at December 31, 2015 and 2016). 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, 2016 (in millions):

	Total	< 1 year	1-3 years	3-5 years	> 5 years
Long-term debt obligations[1]	$ 4,100.0	$ —	$ 800.0	$ 600.0	$ 2,700.0
Interest obligations[1]	2,860.4	204.3	365.2	280.9	2,010.0
Operating lease obligations	238.4	38.6	54.0	35.2	110.6
Pension and postretirement medical obligations[2]	72.1	23.1	36.7	3.1	9.2
Purchase commitments:					
Product purchase commitments[3]	166.4	111.3	45.2	9.9	—
Utility purchase commitments	19.4	8.4	9.4	1.5	0.1
Derivative instruments[4]	—	—	—	—	—
Equity-based incentive awards[5]	40.0	22.6	17.4	—	—
Capital project purchase obligations	108.4	102.6	5.8	—	—
Maintenance obligations	90.3	90.0	0.3	—	—
Other	8.5	4.6	2.1	1.8	—
Total	$ 7,703.9	$ 605.5	$ 1,336.1	$ 932.4	$ 4,829.9

(1) At December 31, 2016, we had no borrowings outstanding under our revolving credit facility. For purposes of this table, we have reflected no assumed borrowings under our revolving credit facility for any periods presented. We assumed that the amounts outstanding under our commercial paper program at December 31, 2016 would be repaid in October 2020, the maturity date of our revolving credit facility, which supports our commercial paper program. Further, we have included interest obligations based on the stated amounts of our fixed-rate obligations. For our variable-rate debt, we calculated interest obligations assuming the weighted-average interest rate of our variable-rate debt at December 31, 2016 on amounts outstanding through the assumed repayment date.

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

(3) 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 as of December 31, 2016. Also, we have excluded certain product purchase agreements for which there is no specified or minimum quantity.

(4) As of December 31, 2016, we had entered into exchange-traded futures contracts representing 4.6 million barrels of petroleum products that we expect to sell in the future and 0.7 million barrels of butane we expect to purchase in the future. At December 31, 2016, we had recorded a net liability of $30.7 million and received margin deposits of $49.9 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.

(5) The total equity-based incentive awards obligation is determined by multiplying the grant date per unit fair value by the number of unit awards granted, multiplied by the percentage of the requisite service period completed, multiplied by the estimated payout percentage of the awards at December 31, 2016. Settlements of these 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.

Environmental

Our operations are subject to federal, state and local environmental laws and regulations. We have accrued liabilities for estimated costs at our facilities and properties. We record liabilities when environmental costs are probable and can be reasonably estimated. The determination of amounts recorded for environmental liabilities involves significant judgments and assumptions by management. Due to the inherent uncertainties involved in determining environmental liabilities, it is reasonably possible that the actual amounts required to extinguish these liabilities could be materially different from those we have recognized.

Other Items

Commodity Derivative Agreements. Certain of the business activities in which we engage result in our owning various commodities, which exposes us to commodity price risk. We use forward physical commodity contracts and exchange-based futures contracts to help manage this commodity price risk. We use forward physical contracts to purchase butane and sell refined products. We account for these forward physical contracts as normal purchase and sale contracts, using traditional accrual accounting. We use futures contracts to hedge against changes in prices of refined products and crude oil that we expect to sell and of butane that we expect to purchase in future periods. We use and account for those futures contracts that qualify for hedge accounting treatment as either cash flow or fair value hedges, and we use and account for those futures contracts that do not qualify for hedge accounting treatment as economic hedges.

As of and for the year ended December 31, 2016, our open derivative contracts and the impact of the derivatives we settled during the period were as follows:

- Futures contracts to hedge against future price changes of certain crude oil tank bottoms, which we account for as fair value hedges. The cumulative amount of gains from these agreements was recorded as an adjustment to the asset being hedged, and there has been no ineffectiveness recognized for these hedges. We exclude the differential between the current spot price and forward price from our assessment of hedge effectiveness for these fair value hedges, and we recognize the net change in this excluded amount as other income on our consolidated statements of income.

- Futures contracts used to hedge sales and purchases of refined products, crude oil and butane related to our butane blending, fractionation, and certain crude oil inventory activities. These contracts were accounted for as economic hedges, with the change in fair value of contracts that hedge future sales recorded to product sales, and the change in fair value of contracts that hedge future purchases recorded to cost of product sales.

- Futures contracts used to hedge sales of refined products and crude oil inventory we carry that resulted from pipeline product overages. These contracts were accounted for as economic hedges, with the change in fair value of these contracts recorded to operating expense.

For further information regarding the quantities of refined products and crude oil hedged at December 31, 2016 and the fair value of open hedge contracts at that date, please see *Item 7A. Quantitative and Qualitative Disclosures about Market Risk*.

The following tables provide a summary of the impacts of the mark-to-market gains and losses associated with these futures contracts on our results of operations for the respective periods presented (in millions):

	Year Ended December 31, 2014				
	Product Sales Revenue	**Cost of Product Sales**	**Operating Expense**	**Other Expense**	**Net Impact on Results of Operations**
Gains (losses) recorded on open futures contracts during the period	$ 83.8	$ (10.6)	$ 8.2	$ (8.6)	$ 72.8
Gains (losses) recognized on settled futures contracts during the period	61.5	(6.5)	9.6	—	64.6
Net impact of futures contracts	$ 145.3	$ (17.1)	$ 17.8	$ (8.6)	$ 137.4

	Year Ended December 31, 2015				
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Other Income	Net Impact on Results of Operations
Gains (losses) recorded on open futures contracts during the period	$ 41.3	$ (5.2)	$ 3.1	$ 1.0	$ 40.2
Gains (losses) recognized on settled futures contracts during the period	27.1	(3.8)	8.7	—	32.0
Net impact of futures contracts	$ 68.4	$ (9.0)	$ 11.8	$ 1.0	$ 72.2

	Year Ended December 31, 2016				
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Other Income	Net Impact on Results of Operations
Gains (losses) recorded on open futures contracts during the period	$ (30.2)	$ 6.1	$ (3.6)	$ 5.2	$ (22.5)
Gains (losses) recognized on settled futures contracts during the period	(8.4)	4.9	(1.4)	—	(4.9)
Net impact of futures contracts	$ (38.6)	$ 11.0	$ (5.0)	$ 5.2	$ (27.4)

Pipeline Tariff Increase. 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 deemed competitive 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%. The change in PPI-FG for 2016 is preliminarily expected to be negative 1%. As a result, we expect to slightly increase rates in the 40% of our markets that are subject to the FERC's index methodology on July 1, 2017. 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, 2017, consistent with the 2016 rate increase for our competitive markets.

Board of Director Changes in 2016. In June 2016, Lori A. Gobillot and Edward J. Guay were elected to our general partner's board of directors as independent directors.

In March 2016, Patrick C. Eilers, an independent member of our general partner's board of directors, resigned from the board to pursue other interests. Mr. Eilers accepted a full-time position with a firm that has a policy restricting its employees from serving on the board of directors of a public company. Mr. Eilers' resignation was not the result of any disagreement with us on any matter relating to our operations, policies or practices.

Related Party Transactions. See Note 11 – *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.

Environmental Liabilities

We estimate the liabilities associated with environmental expenditures based on site-specific project plans for remediation, taking into account prior remediation experience. Remediation project managers evaluate each known case of environmental liability to determine what associated costs can be reasonably estimated and to ensure compliance with all applicable federal and state requirements. The accounting estimate relative to environmental remediation costs is a critical accounting estimate for each of our operating segments because: (i) estimated expenditures are subject to cost fluctuations and could change materially, (ii) as remediation work is performed and additional information relative to each specific site becomes known, cost estimates for those sites could change materially, (iii) unanticipated third-party liabilities may arise, (iv) it is difficult to determine the amounts, if any, of penalties that may be levied by governmental agencies with regard to certain environmental events, and (v) when changes in federal, state and local environmental regulations occur, these changes could significantly impact the amount of our environmental liability accruals.

A defined process for project review is integrated into our system integrity plan. Each year our remediation project managers meet to evaluate, in detail, our known environmental sites. The purpose of the annual project review is to assess all aspects of each project, evaluating what actions will be required to achieve regulatory compliance and estimating the costs and timing to execute the regulatory phases that can be reasonably estimated. During the site-specific evaluations, we utilize all known information in conjunction with professional judgment and experience to determine the appropriate approach for remediation and to assess liabilities. The process to achieve regulatory compliance consists of site investigation/delineation, site remediation and long-term monitoring. Each of these phases can, and often does, include unknown variables that complicate the task of evaluating the estimated costs to completion. At each accounting period-end, we re-evaluate our environmental estimates taking into account any new incidents that have occurred since the last annual meeting of the remediation project managers, any changes in the site situation remediation, including work to date, additional findings or changes in federal or state regulations and changes in cost estimates. Changes in our environmental liabilities since December 31, 2014 were as follows (in millions):

Balance	2015		Balance	2016		Balance
12/31/14	Accruals	Expenditures	12/31/15	Accruals	Expenditures	12/31/16
$36.3	$6.3	$(11.2)	$31.4	$8.4	$(15.8)	$24.0

During 2016, we accrued $8.4 million of environmental liabilities. Of this amount, $8.6 million related to product releases that occurred during 2016, and the remaining accrual adjustments of $(0.2) million related to historical releases. At December 31, 2016, we had recognized $4.1 million of receivables from insurance carriers associated with environmental claims.

During 2015, we accrued $6.3 million of environmental liabilites. Of this amount, $5.6 million related to product releases that occurred during 2015 and $0.7 million related to historical releases. At December 31, 2015, we had recognized $2.6 million of receivables from insurance carriers associated with environmental claims.

We based our period-end environmental liabilities on estimates that are subject to change, and any changes to these estimates would affect our results of operations and financial position. Any increase in our environmental liabilities would decrease our operating profit and net income by the same amount, which would negatively impact basic and diluted net income per limited partner unit.

Pension and Postretirement Obligations

We sponsor two union pension plans covering certain employees ("USW plan" and "IUOE plan"), a pension plan for all non-union employees ("Salaried plan") and a postretirement benefit plan for certain 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, expected rate of compensation increase and the assumed health care cost trend rate. 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	$ (3,356)	$ 3,858	$ (23,407)	$ 28,350
Expected long-term rate of return on plan assets	$ (1,073)	$ 2,128	$ —	$ —
Rate of compensation increase	$ 2,614	$ (2,773)	$ 11,761	$ (11,894)
Other postretirement benefits:				
Discount rate	$ (129)	$ 164	$ (1,437)	$ 1,840
Assumed health care cost trend rate	$ 87	$ (81)	$ 521	$ (481)

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
Projected return on assets	$ (131)	$ 131
Rate of compensation increase	$ 3,483	$ (3,496)

The discount rate directly affects the measurement of the benefit obligations of our pension and other postretirement benefit plans. The objective of the discount rate is to determine the amount, if invested at the December 31st 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. We base the assumed health care cost trend rates on national trend rates adjusted for our actual historical claims experience and plan design. An increase in this rate causes the other postretirement benefit obligation and expense to increase.

Valuation of Assets

The application of business combination and impairment accounting requires us to use significant estimates and assumptions in determining the fair value of assets and liabilities. The acquisition method of accounting for business combinations requires us to estimate the fair value of assets acquired and liabilities assumed to allocate the proper amount of the purchase price consideration between goodwill and the assets that are depreciated and amortized. We record intangible assets separately from goodwill and amortize intangible assets with finite lives over their estimated useful life as determined by management. We do not amortize goodwill or intangible assets with indefinite lives but instead periodically assess these for impairment.

For all material acquisitions, we engage the services of an independent appraiser to assist us in determining the fair value of the acquired assets and liabilities, including goodwill; however, the ultimate determination of those values is the responsibility of our management. We base our estimates on assumptions believed to be reasonable, but which are inherently uncertain. These valuations require the use of management's assumptions, which would not reflect unanticipated events and circumstances that may occur.

Goodwill and Impairment of Long-Lived Assets

Goodwill. At December 31, 2015 and 2016, we had recognized goodwill of $53.3 million. Goodwill resulting from a business combination is not subject to amortization. As required by Accounting Standards Codification ("ASC") 350, *Goodwill and Other*, we test goodwill at the reporting unit level for impairment annually and between annual tests if events or changes in circumstances indicate the carrying amount may exceed fair value. For 2016, we performed a qualitative assessment to determine whether the fair value of our reporting units was more likely than not less than their respective carrying amounts. Our evaluation consisted of assessing the general impact of how a number of different elements would affect the fair value of our reporting units, including the current and projected future earnings of our reporting units, our capitalization, our current slate of capital projects, the growth in the distributions we pay to our unitholders, current and future interest rates and the impact of lower commodity prices on our earnings and the acquisition markets. Our qualitative assessment indicated that there was no need to conduct further quantitative testing for goodwill impairment and our analysis did not reflect any reporting units at risk of impairment. Different judgments from those we used in our qualitative analysis could result in the requirement to perform a quantitative goodwill impairment analysis. Results from that quantitative analysis could use projections and estimates different from those others might use, which could result in the recognition of an impairment loss. Any such impairment losses recognized could be material to our results of operations. The accounting estimate relative to assessing the impairment of goodwill is a critical accounting estimate for our refined products and crude oil segments. Based on our assessments at December 31, 2014, 2015 and 2016, we did not record a goodwill impairment for any of these years.

Impairment of Long-Lived Assets. As prescribed by ASC 360-10-05, *Property, Plant and Equipment-General-Impairment or Disposal of Long-Lived Assets*, we assess property, plant and equipment for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets 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.

Determination as to whether and how much an asset is 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. Impairments recognized during 2014, 2015 and 2016 were not material.

An estimate as to the sensitivity to earnings for these periods had we used other assumptions in our impairment reviews and impairment calculations is not practicable, given the broad range of our property, plant and equipment and the number of assumptions involved in the estimates. Favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an increase in impairments recognized.

For specific details of the impairment analysis of our Corpus Christi condensate splitter, please refer to Note 2 – *Summary of Significant Accounting Policies* in *Item 8. Financial Statements and Supplementary Data* of this report.

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.

Forward-Looking Statements

Certain matters discussed in this Annual Report on Form 10-K include forward-looking statements within the meaning of the federal securities laws that discuss our expected future results based on current and pending business operations. Forward-looking statements can be identified by words such as “anticipates,” “believes,” “continue,” “could,” “estimates,” “expects,” “forecasts,” “goal,” “guidance,” “intends,” “may,” “might,” “plans,” “potential,” “projected,” “scheduled,” “should,” “will” and other similar expressions. Although we believe our forward-looking statements are based on reasonable assumptions, 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. Therefore, actual outcomes and results may be materially different from the results stated or implied in such forward-looking statements included in this report.

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

- overall demand for refined products, crude oil, liquefied petroleum gases and ammonia in the U.S.;
- price fluctuations for refined products, crude oil, liquefied petroleum gases and ammonia 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 growth 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 and geothermal energy, increased use of biofuels such as ethanol and biodiesel, increased conservation or fuel efficiency, as well as regulatory developments or other trends that could affect demand for our services;
- changes in the 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 storage in our refined products, crude oil or marine terminals;
- 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 implemented by the Federal Energy Regulatory Commission, the U.S. Surface Transportation Board or state regulatory agencies;
- shut-downs or cutbacks at refineries, oil wells, petrochemical plants, ammonia production facilities 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;
- the occurrence of natural disasters, terrorism, 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 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 that govern product quality specifications or renewable fuel obligations that could impact our ability to produce gasoline volumes through our butane blending activities or that could 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 or our subsidiaries;
- 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 ammonia, and the operation, acquisition and construction of assets related to such activities.

This list of important factors is not exclusive. 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.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

We may be exposed to market risk through changes in commodity prices and interest rates and have established policies to monitor and control these market risks. We use derivative agreements to help manage our exposure to commodity price and interest rate risks.

Commodity Price Risk

Our commodity price risk primarily arises from our butane blending and fractionation activities, and from managing product overages associated with our refined products and crude oil pipelines and certain tank bottoms. We use derivatives such as forward physical contracts and exchange-traded futures contracts to help us manage commodity price risk.

Forward physical contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting. As of December 31, 2016, we had commitments under forward purchase and sale contracts as follows (in millions):

	Total	< 1 Year	1 – 3 Years
Forward purchase contracts – notional value	$ 166.4	$ 111.3	$ 55.1
Forward purchase contracts – barrels	3.9	2.7	1.2
Forward sales contracts – notional value	$ 68.2	$ 68.2	$ —
Forward sales contracts – barrels	1.0	1.0	—

We use futures contracts to hedge against changes in the price of petroleum products we expect to sell or purchase. At December 31, 2016, we had open futures contracts representing 4.6 million barrels of petroleum products we expect to sell in the future. Additionally, we had open futures contracts for 0.7 million barrels of butane we expect to purchase in the future. At December 31, 2016, the fair value of our open futures contracts was a liability of $30.7 million. Some of these futures contracts qualify for hedge accounting treatment, and we designate and account for these contracts as either cash flow or fair value hedges. We account for futures contracts that do not qualify for hedge accounting treatment as economic hedges, and we recognize the changes in the fair value of these contracts currently in earnings.

At December 31, 2016, we had open futures contracts representing 3.9 million barrels of petroleum products we expect to sell in the future that we accounted for as economic hedges. Relative to these agreements, a $10.00 per barrel increase in the price of these futures contracts for the related petroleum products would result in a $39.0 million decrease in our operating profit and a $10.00 per barrel decrease in the price of these futures contracts would result in a $39.0 million increase in our operating profit.

At December 31, 2016, we had open futures contracts representing 0.7 million barrels of butane we expect to purchase in the future that we accounted for as economic hedges. Relative to these agreements, a $10.00 per barrel increase in the price of butane would result in a $7.0 million increase in our operating profit and a $10.00 per barrel decrease in the price of butane would result in a $7.0 million decrease in our operating profit.

The increases or decreases in operating profit we recognize from our open futures contracts would be substantially offset by higher or lower product sales revenue or cost of product sales when the physical sale or purchase of those products occur. These contracts may be for the purchase or sale of product in markets different from those in which we are attempting to hedge our exposure and the resulting hedges may not eliminate all price risks.

Interest Rate Risk

Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk.

During 2016, we entered into $100.0 million of forward-starting interest rate swap agreements to hedge against the risk of variability of future interest payments on a portion of debt we anticipate issuing in 2018. The fair value of these contracts at December 31, 2016 was a net asset of $14.1 million. We account for these agreements as cash flow hedges. A 0.125% decrease in interest rates would result in a decrease in the fair value of this asset of approximately $2.3 million. A 0.125% increase in interest rates would result in an increase of the fair value of this asset of approximately $2.3 million.

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, 2016. 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, 2016, 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 this 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, 2016. The report, which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2016, 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/ AARON L. MILFORD

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

Report of Independent Registered Public Accounting Firm

The Board of Directors of Magellan GP, LLC
General Partner of Magellan Midstream Partners, L.P.
and the Limited Partners of Magellan Midstream Partners, L.P.

We have audited Magellan Midstream Partners, L.P.'s internal control over financial reporting as of December 31, 2016, 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). Magellan Midstream Partners, L.P.'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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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.

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.

In our opinion, Magellan Midstream Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Magellan Midstream Partners, L.P. as of December 31, 2016 and 2015, and 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, 2016, and our report dated February 17, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 17, 2017

Report of Independent Registered Public Accounting Firm

The Board of Directors of Magellan GP, LLC
General Partner of Magellan Midstream Partners, L.P.
and the Limited Partners of Magellan Midstream Partners, L.P.

We have audited the accompanying consolidated balance sheets of Magellan Midstream Partners, L.P. as of December 31, 2016 and 2015, and 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, 2016. These financial statements are the responsibility of Magellan Midstream Partners, L.P.'s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Magellan Midstream Partners, L.P. at December 31, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, 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), Magellan Midstream Partners, L.P.'s internal control over financial reporting as of December 31, 2016, 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 17, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 17, 2017

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

	Year Ended December 31,		
	2014	2015	2016
Transportation and terminals revenue	$ 1,459,267	$ 1,544,746	$ 1,591,119
Product sales revenue	878,974	629,836	599,602
Affiliate management fee revenue	22,111	13,871	14,689
Total revenue	2,360,352	2,188,453	2,205,410
Costs and expenses:			
Operating	500,901	525,902	529,759
Cost of product sales	594,585	447,273	493,338
Depreciation and amortization	161,741	166,812	178,142
General and administrative	148,288	151,329	147,815
Total costs and expenses	1,405,515	1,291,316	1,349,054
Earnings of non-controlled entities	19,394	66,483	78,696
Operating profit	974,231	963,620	935,052
Interest expense	145,862	158,895	194,187
Interest income	(1,540)	(1,276)	(1,402)
Interest capitalized	(22,803)	(14,442)	(27,375)
Gain on exchange of interest in non-controlled entity	—	—	(28,144)
Other expense (income)	8,573	(1,015)	(8,203)
Income before provision for income taxes	844,139	821,458	805,989
Provision for income taxes	4,620	2,336	3,218
Net income	$ 839,519	$ 819,122	$ 802,771
Basic net income per limited partner unit	$ 3.69	$ 3.60	$ 3.52
Diluted net income per limited partner unit	$ 3.69	$ 3.59	$ 3.52
Weighted average number of limited partner units outstanding used for basic net income per unit calculation(1)	227,260	227,550	227,926
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation(1)	227,626	227,888	228,057

(1) See Note 15–*Long-Term Incentive Plan* for additional information regarding our weighted average unit calculations.

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2014	**2015**	**2016**
Net income	$ 839,519	$ 819,122	$ 802,771
Other comprehensive income:			
Derivative activity:			
Net loss on cash flow hedges[1]	(30,090)	(14,904)	(6,699)
Reclassification of net loss (gain) on cash flow hedges to income[1]	(124)	1,365	2,049
Changes in employee benefit plan assets and benefit obligations recognized in other comprehensive income:			
Net actuarial loss[2]	(33,937)	(8,359)	(2,452)
Plan amendment[2]	—	3,610	—
Amortization of prior service credit[2]	(3,680)	(3,713)	(3,516)
Amortization of actuarial loss[2]	3,986	7,191	5,525
Settlement cost[2]	1,809	—	202
Total other comprehensive loss	(62,036)	(14,810)	(4,891)
Comprehensive income	$ 777,483	$ 804,312	$ 797,880

(1) See Note 13–*Derivative Financial Instruments* for details of the amount of gain/loss recognized in accumulated other comprehensive loss (“AOCL”) on derivatives and the amount of gain/loss reclassified from AOCL into income.

(2) See Note 10–*Employee Benefit Plans* for additional detail of the changes in employee benefit plan assets and benefit obligations that are recognized in other comprehensive income (loss).

See notes to consolidated financial statements.

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

	December 31, 2015	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 28,731	$ 14,701
Trade accounts receivable	83,893	105,689
Other accounts receivable	12,701	25,761
Inventory	130,868	134,378
Energy commodity derivatives contracts, net	39,243	—
Energy commodity derivatives deposits	—	49,899
Other current assets	43,418	39,966
Total current assets	338,854	370,394
Property, plant and equipment	6,166,766	6,783,737
Less: accumulated depreciation	1,347,537	1,507,996
Net property, plant and equipment	4,819,229	5,275,741
Investments in non-controlled entities	765,628	931,255
Long-term receivables	20,374	23,870
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of $13,709 and $2,136 at December 31, 2015 and 2016, respectively)	1,856	51,976
Other noncurrent assets	42,366	65,577
Total assets	$ 6,041,567	$ 6,772,073
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 104,094	$ 77,248
Accrued payroll and benefits	51,764	45,690
Accrued interest payable	51,296	65,643
Accrued taxes other than income	51,587	50,166
Environmental liabilities	15,679	10,249
Deferred revenue	81,627	101,891
Accrued product purchases	31,339	51,600
Energy commodity derivatives contracts, net	—	30,738
Energy commodity derivatives deposits	24,252	—
Current portion of long-term debt, net	250,335	—
Other current liabilities	51,099	48,431
Total current liabilities	713,072	481,656
Long-term debt, net	3,189,287	4,087,192
Long-term pension and benefits	77,551	71,461
Other noncurrent liabilities	24,162	25,868
Environmental liabilities	15,759	13,791
Commitments and contingencies		
Partners' capital:		
Limited partner unitholders (227,427 units and 227,784 units outstanding at December 31, 2015 and 2016, respectively)	2,118,086	2,193,346
Accumulated other comprehensive loss	(96,350)	(101,241)
Total partners' capital	2,021,736	2,092,105
Total liabilities and partners' capital	$ 6,041,567	$ 6,772,073

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2014	2015	2016
Operating Activities:			
Net income	$ 839,519	$ 819,122	$ 802,771
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	161,741	166,812	178,142
Loss on sale and retirement of assets	7,223	7,871	11,190
Earnings of non-controlled entities	(19,394)	(66,483)	(78,696)
Distributions from investments in non-controlled entities	3,086	66,285	78,723
Equity-based incentive compensation expense	27,284	24,245	19,358
Settlement cost, amortization of prior service credit and actuarial loss	2,115	3,478	2,211
Gain on exchange of interest in non-controlled entity	—	—	(28,144)
Changes in components of operating assets and liabilities (Note 3)	85,727	48,362	(21,515)
Net cash provided by operating activities	1,107,301	1,069,692	964,040
Investing Activities:			
Additions to property, plant and equipment, net[(1)]	(363,250)	(621,151)	(674,159)
Proceeds from sale and disposition of assets	10,780	3,371	7,552
Acquisition of assets	(75,000)	—	—
Acquisition of business	—	(54,678)	—
Investments in non-controlled entities	(408,001)	(152,466)	(200,023)
Distributions in excess of earnings of non-controlled entities	5,487	14,155	9,264
Net cash used by investing activities	(829,984)	(810,769)	(857,366)
Financing Activities:			
Distributions paid	(568,806)	(662,948)	(739,157)
Net commercial paper borrowings (repayments)	296,942	(16,981)	(229,975)
Borrowings under long-term notes	257,713	499,589	1,142,997
Payments on notes	(250,000)	—	(250,000)
Debt placement costs	(2,912)	(6,223)	(10,906)
Net payment on financial derivatives	(3,613)	(42,908)	(19,287)
Settlement of tax withholdings on equity-based incentive compensation	(14,813)	(17,784)	(14,376)
Net cash used by financing activities	(285,489)	(247,255)	(120,704)
Change in cash and cash equivalents	(8,172)	11,668	(14,030)
Cash and cash equivalents at beginning of period	25,235	17,063	28,731
Cash and cash equivalents at end of period	$ 17,063	$ 28,731	$ 14,701
Supplemental non-cash investing and financing activities:			
Contribution of property, plant and equipment to a non-controlled entity	$ —	$ 13,252	$ —
Issuance of limited partner units in settlement of equity-based incentive plan awards	$ 7,315	$ 8,045	$ 7,289

(1) Additions to property, plant and equipment	$ (366,445)	$ (623,289)	$ (653,528)
Changes in accounts payable and other current liabilities related to capital expenditures	3,195	2,138	(20,631)
Additions to property, plant and equipment, net	$ (363,250)	$ (621,151)	$ (674,159)

See notes to consolidated financial statements.

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

	Limited Partners	Accumulated Other Comprehensive Loss	Total Partners' Capital
Balance, January 1, 2014	$ 1,666,946	$ (19,504)	$ 1,647,442
Comprehensive income:			
Net income	839,519	—	839,519
Total other comprehensive loss	—	(62,036)	(62,036)
Total comprehensive income (loss)	839,519	(62,036)	777,483
Distributions	(568,806)	—	(568,806)
Equity-based incentive compensation expense	19,963	—	19,963
Issuance of limited partner units in settlement of equity-based incentive plan awards	7,315	—	7,315
Settlement of tax withholdings on equity-based incentive compensation	(14,813)	—	(14,813)
Other	(351)	—	(351)
Balance, December 31, 2014	1,949,773	(81,540)	1,868,233
Comprehensive income:			
Net income	819,122	—	819,122
Total other comprehensive loss	—	(14,810)	(14,810)
Total comprehensive income (loss)	819,122	(14,810)	804,312
Distributions	(662,948)	—	(662,948)
Equity-based incentive compensation expense	22,248	—	22,248
Issuance of limited partner units in settlement of equity-based incentive plan awards	8,045	—	8,045
Settlement of tax withholdings on equity-based incentive compensation	(17,784)	—	(17,784)
Other	(370)	—	(370)
Balance, December 31, 2015	2,118,086	(96,350)	2,021,736
Comprehensive income:			
Net income	802,771	—	802,771
Total other comprehensive loss	—	(4,891)	(4,891)
Total comprehensive income (loss)	802,771	(4,891)	797,880
Distributions	(739,157)	—	(739,157)
Equity-based incentive compensation expense	19,358	—	19,358
Issuance of limited partner units in settlement of equity-based incentive plan awards	7,289	—	7,289
Settlement of tax withholdings on equity-based incentive compensation	(14,376)	—	(14,376)
Other	(625)	—	(625)
Balance, December 31, 2016	$ 2,193,346	$(101,241)	$ 2,092,105

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. We are a Delaware limited partnership and our limited partner units trade on the New York Stock Exchange under the ticker symbol "MMP." Magellan GP, LLC, a wholly owned Delaware limited liability company, serves as our general partner.

Description of Business

We are principally engaged in the transportation, storage and distribution of refined petroleum products and crude oil. As of December 31, 2016, our asset portfolio, including the assets of our joint ventures, consisted of:

- our refined products segment, comprised of our 9,700-mile refined products pipeline system with 53 terminals as well as 26 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

- our crude oil segment, comprised of approximately 2,200 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 26 million barrels, of which 16 million are used for contract storage; and

- our marine storage segment, consisting of five marine terminals located along coastal waterways with an aggregate storage capacity of approximately 26 million barrels.

Description of Products

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

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

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

- *blendstocks* are 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 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 and condensate* are used as feedstocks by refineries and petrochemical facilities;

- *biofuels*, such as ethanol and biodiesel, are typically blended with other refined products as required by government mandates; and

- *ammonia* is primarily used as a nitrogen fertilizer.

Except for ammonia, we use the term *petroleum products* to describe any, or a combination, of the above-noted products.

2. Summary of Significant Accounting Policies

Basis of Presentation. Our consolidated financial statements include our refined products, crude oil and marine storage 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.

Use of Estimates. The preparation of our consolidated financial statements in conformity with generally accepted accounting principles in the U.S. ("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, 2015 and 2016, we believed our credit risk relative to these funds was minimal.

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 based on historical dealings and to other 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.

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 market.

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. The range of depreciable lives by asset category is detailed in Note 8—*Property, Plant and Equipment and Other Intangibles*.

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.

Investments in Non-Controlled Entities. We account for investments greater than 20% 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 $76.7 million and $61.3 million at December 31, 2015 and 2016, 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 2014, 2015 and 2016.

Goodwill and Other Intangible Assets. Goodwill resulting from a business combination is not subject to amortization. We test goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount.

We amortize other intangible assets with finite lives over their estimated useful lives of 6 years up to 30 years. The weighted-average asset life of our other intangible assets at December 31, 2016 was approximately 21 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. We review our other intangible assets for impairment whenever events or changes in circumstances indicate we should assess the recoverability of the carrying amount of the intangible asset. We recognized no impairments for other intangible assets in 2014, 2015 and 2016.

Impairment of Long-Lived Assets. We evaluate our long-lived assets of identifiable business activities, other than those held for sale, for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. We base the determination of whether impairment has occurred on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. We calculate the amount of the impairment recognized as the excess of the carrying amount of the asset over the fair value of the assets, as determined either through reference to similar asset sales or by estimating the fair value using a discounted cash flow approach.

Judgments and assumptions are inherent in management's estimate of undiscounted future cash flows used to determine recoverability of an asset and the estimate of an asset's fair value used to calculate the amount of impairment to recognize. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the financial statements.

In January 2017, the sole customer of our Corpus Christi condensate splitter, an affiliate of Trafigura, AG, terminated its agreement with us, and we are pursuing legal remedies based on our belief that the termination was a breach of its obligations. These events triggered an impairment analysis of the Corpus Christi splitter asset group within our crude oil segment. Our assessment included multiple scenarios of undiscounted future cash flows that considered variables including pricing assumptions, fixed and variable costs, expected yields and throughput capacity of the condensate splitter. This assessment resulted in the undiscounted cash flows significantly exceeding the approximately $300 million carrying value of the asset group, and no impairment was recorded. The use of different judgments and assumptions associated with the measurement variables noted, particularly the pricing assumptions, fixed and variable costs and expected yields, could result in lower projections of future cash flows, which could result in an impairment loss.

Interest Capitalized. 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 was 4.9%, 4.7% and 4.9% for the years ended December 31, 2014, 2015 and 2016, respectively.

Pension and Postretirement Medical and Life Benefit Obligations. We sponsor three pension plans that collectively cover substantially all of our employees, a postretirement medical and life benefit plan for certain employees and a defined contribution plan. Our pension and postretirement benefit liabilities represent the funded status of the present value of benefit obligations of these plans.

We develop pension, postretirement medical and life benefits costs from 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.

Derivative Financial Instruments. We use derivative instruments to manage market price risks associated with inventories, interest rates, tank bottoms and certain forecasted transactions. Our policies prohibit us from engaging in speculative trading activities. For certain physical forward commodity derivative contracts, accounting guidance provides for and we apply the normal purchase / normal sale exception, 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 back-tested once the forecasted period has passed to determine whether similar forward contracts are probable of physical delivery in the future. For all other derivative contracts, we record the agreements on our balance sheets at fair value.

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 or that do not qualify for the normal purchase / normal sales exception 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.

We enter into commodity-based futures contracts traded on the New York Mercantile Exchange to hedge against price changes on a portion of the petroleum products we expect to sell or purchase in the future, as well as against changes in the fair value of certain tank bottoms. We record the effective portion of the gains or losses for those contracts that are designated as cash flow hedges in other comprehensive income and the ineffective portion in product sales revenue. We reclassify gains and losses from contracts designated as cash flow hedges from other comprehensive income to product sales revenue when the hedged transaction occurs and we terminate the derivative agreement. We record the effective portion of the gains or losses for those 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 hedges that are not designated as hedges in product sales revenue or cost of product sales, except for those contracts that hedge the inventories associated with our pipeline system overages, which are recorded in operating expenses.

We use interest rate derivatives to help manage interest rate risk. We record any ineffectiveness on derivatives designated as hedging instruments to interest expense and the change in fair value of interest rate derivatives that we do not designate as hedging instruments to other income or expense in our results of operations. For the effective portion of interest rate cash flow hedges, we record the noncurrent portion of unrealized gains or losses as an adjustment to other comprehensive income with the current portion recorded as an adjustment to interest expense. For the effective portion of fair value hedges on long-term debt, we record the noncurrent portion of gains or losses as an adjustment to long-term debt with the current portion recorded as an adjustment to interest expense.

Revenue Recognition. Sales revenue is recognized based on contracts or other persuasive evidence of an arrangement with the customer that includes fixed or determinable prices in which collectability is reasonably assured. Product sales revenue is recognized for products upon delivery and when the customer assumes the risks and rewards of ownership.

We recognize pipeline transportation revenue for crude oil shipments when our customers take possession of their product from our system. For shipments of refined products and ammonia under published tariffs that combine transportation and terminalling services, we recognize revenue when our customers take possession 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 agreements that require counterparties to ship a minimum volume over an agreed-upon period. Revenue pursuant to such agreements is recognized at the earlier of when the volume is shipped or when the counterparty's ability to meet the minimum volume commitment has expired.

The tariffs we charge for our pipeline transportation systems are primarily regulated by the Federal Energy Regulatory Commission ("FERC"); however, certain tariffs are regulated by the Surface Transportation Board or state regulatory authorities. Our 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 these product quantities as tender deductions. We receive tender deductions from our customers as consideration for product losses during the transportation of their refined products or crude oil within our pipeline systems. Our customers are guaranteed delivery of the amount of their injected volumes, net of tender deductions, irrespective of what our actual product losses may be during the delivery process. Tender deduction revenue is recognized when the transportation barrels are received and is recorded at the fair value of the product received.

We recognize injection service fees associated with additives upon injection to the customer's product, which occurs at the time we deliver the product to our customers. We recognize tank storage, pipeline capacity leases, terminalling, throughput, ethanol loading and unloading services, laboratory testing, data services, pipeline operation fees and other miscellaneous service-related revenue upon completion of the rendered services. We recognize product sales upon delivery of the product to the customer. We record back-to-back purchases and sales of refined products where we are acting as an agent to facilitate refined product sales between a supplier and a customer on a net basis.

Deferred Transportation Revenue and Costs. Generally, we invoice customers on our refined products pipeline 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 deferred liability. The value of this liability is calculated as the total of the volume of each product type, for each pipeline region, multiplied by the average tariff rate for that product type for the most recent month invoiced to our customers. We use the most recent month's average tariff rate because the product in our pipeline system generally turns over every month. Additionally, at each period end, we defer the direct costs we have incurred associated with these in-transit products, until delivery occurs, as a deferred asset. These direct costs are estimated based on our average per-barrel direct delivery cost for the current year 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 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 deferred revenues and costs are determined using judgments and assumptions that management considers reasonable.

Pipeline Over/Short Product. Each period end we measure the volume of each type of product in our pipeline system, which is compared to the volumes of our customers' inventories (as adjusted for tender deductions). To the extent that the product volumes in our pipeline system exceed the volumes of our customers' book inventories, we increase our product inventories and recognize a gain; however, to the extent the product in our pipeline system is less than our customers' book inventories, we record a liability (for product owed to our customers) and recognize a loss. The product gains and losses we recognize are recorded based on period-end product market prices, and we include those gains or losses in operating expenses on our consolidated statements of income.

Excise Taxes Charged to Customers. Revenues are recorded net of all amounts charged to our customers for excise taxes.

Equity-Based Incentive Compensation. The compensation committee of our general partner's board of directors (the "compensation committee") has approved incentive awards of phantom units representing limited partner interests in us to certain employees and to independent members of our general partner's board of directors. The phantom unit awards granted include: (i) performance-based awards which are issued to certain officers, managers and other key employees ("performance-based awards"), (ii) time-based awards which are issued to certain officers, managers and key employees ("time-based awards"), and (iii) performance awards which are issued to independent members of our general partner's board of directors ("director awards"). All of the performance-based and time-based awards, as well as director awards that have been deferred into the Director Deferred Compensation Plan, include distribution equivalent rights.

We classify our performance-based and time-based unit awards as equity, and we classify the director awards as liability awards. Fair value for awards classified as equity is determined on the grant date of the award, and we recognize this value as compensation expense ratably over the requisite service period, which is the vesting period of each unit award. Because all of our outstanding unit awards contain distribution equivalent rights, the per-unit fair value of our equity awards is the closing price of our limited partner units on the grant date. However, the per-unit fair value of our performance-based unit awards also includes the fair value of the market-based component of those awards. Compensation expense for our equity awards is calculated as the number of unit awards less forfeitures, multiplied by the per unit 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. Compensation expense for our liability awards is calculated as the number of phantom units awarded, multiplied by the per unit fair value of those awards on the last day of the reporting period, less previously-recognized compensation expense.

Our outstanding performance-based awards include provisions that can result in payouts to the recipients of these awards of 0% to 200% of the targeted amount of the award. Additionally, these performance-based awards are subject to a total unitholder return market performance adjustment, which could increase or decrease the payout of these awards by as much as 50%. The market performance adjustment component is based on our total unitholder return compared to the total unitholder returns of specified peer companies. Judgments and assumptions of the final award payouts are inherent in the accruals recorded for equity-based incentive compensation costs. The use of alternate judgments and assumptions could result in the recognition of different levels of equity-based incentive compensation costs.

Payouts related to time-based awards are based solely on the completion of the requisite service period by the employee. Time-based awards contain no provisions which would provide for a payout to the employee of anything other than the original number of units awarded and the associated distribution equivalents.

The vesting period for both the performance-based and time-based 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. We settle performance-based and time-based awards that have vested by issuing new limited partner units, except for the associated statutory tax withholding, which we settle by paying in cash. Director awards may be deferred and may be settled in cash or by issuing limited partner units. 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.

Contingencies and Environmental. 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.

Income Taxes. We are a partnership for income tax purposes and, therefore, have not been 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 the individual partners through the allocation 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 partner'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, 2014, 2015 and 2016, our qualifying income met the statutory requirement.

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 limited partner unit for each period by dividing net income by the weighted-average number of limited partner units outstanding. The difference between our actual limited partner units outstanding and our weighted-average number of limited partner units outstanding used to calculate net income per limited partner unit is due to the impact of: (i) the phantom units issued to independent directors which is 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 limited partner 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 grants associated with our long-term incentive plan which have not yet vested in periods where contingent performance metrics have been met.

New Accounting Pronouncements

In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-09, *Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting*, which is part of the FASB's initiative to simplify accounting standards. The guidance requires an entity to make an entity-wide accounting policy election to either estimate the number of awards that are expected to vest or account for forfeitures when they occur, and allows equity classification for awards where employees elect to withhold up to the maximum statutory tax rates in the applicable jurisdictions. The new standard also requires cash paid by employers when directly withholding shares for tax withholding purposes to be classified as a financing activity in the statement of cash flows.

We elected to early adopt ASU 2016-09 during the first quarter of 2016, and this adoption did not have a material impact on our consolidated financial statements. In conjunction with our adoption of this new accounting standard, we elected to account for equity-based compensation forfeitures as they occur. Additionally, and consistent with our prior accounting policy, we continue to show cash paid when directly withholding shares for tax withholding purposes as a financing activity in our statements of cash flows.

In February 2016, the FASB issued 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. Public companies are required to adopt the standard for financial reporting periods that start after December 15, 2018, although early adoption is permitted. We are currently in the process of evaluating the impact this new standard will have on our financial statements.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers.* This ASU amends the existing accounting standards for revenue recognition and is based on the principle that revenue should be recognized to depict the transfer of goods or services to a customer at an amount that reflects the consideration a company expects to receive in exchange for those goods or services. We will adopt this ASU as required on January 1, 2018, using the full retrospective method of adoption. We do not expect the adoption of this ASU to have a material impact on our consolidated financial statements.

3. Consolidated Statements of Cash Flows

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

	Year Ended December 31,		
	2014	2015	2016
Trade accounts receivable and other accounts receivable	$ 49,215	$ 3,664	$ (31,107)
Inventory	29,462	26,894	(3,510)
Energy commodity derivatives contracts, net of derivatives deposits	(7,583)	(606)	(692)
Accounts payable	(10,918)	4,107	(4,423)
Accrued payroll and benefits	6,055	3,466	(6,074)
Accrued interest payable	1,038	5,323	14,347
Accrued taxes other than income	9,094	3,699	(1,421)
Deferred revenue	7,978	10,485	20,264
Accrued product purchases	(18,678)	(13,016)	20,261
Current and noncurrent environmental liabilities	(2,144)	(4,904)	(7,398)
Other current and noncurrent assets and liabilities	22,208	9,250	(21,762)
Total	$ 85,727	$ 48,362	$ (21,515)

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 statement of cash flows. At December 31, 2014, 2015 and 2016, the long-term pension and benefits liability was increased by $33.9 million, $4.7 million and $2.5 million, respectively, resulting in a corresponding increase in accumulated other comprehensive loss (“AOCL”).

4. Investments in Non-Controlled Entities

Our investments in non-controlled entities at December 31, 2016 were comprised of:

Entity	Ownership Interest
BridgeTex Pipeline Company, LLC (“BridgeTex”)	50%
Double Eagle Pipeline LLC (“Double Eagle”)	50%
HoustonLink Pipeline Company, LLC (“HoustonLink”)	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%

In February 2016, we transferred our 50% membership interest in Osage Pipe Line Company, LLC (“Osage”) to an affiliate of HollyFrontier Corporation. In conjunction with this transaction, we entered into several commercial agreements with affiliates of HollyFrontier Corporation. We recorded these commercial agreements as $43.7 million of intangible assets and $8.3 million of other receivables in our consolidated balance sheets. The intangible assets will be amortized over the 20-year life of the contracts received. The total gain recorded in 2016 was $28.1 million.

The management fees we have recognized from BridgeTex, Osage, Powder Springs, Saddlehorn and Texas Frontera are reported as affiliate management fee revenue on our consolidated statements of income. In addition, we receive reimbursement from certain of our joint ventures for costs incurred during construction and operations, which we have included as reductions to costs and expenses on our consolidated statements of income. These cost reimbursements totaled $1.3 million and $4.2 million for the year ended December 31, 2015 and 2016, respectively.

For the year ended December 31, 2015 and 2016, we recognized pipeline capacity lease revenue from BridgeTex of $34.6 million and $35.5 million, respectively, which we included in transportation and terminals revenue on our consolidated statements of income.

We recognized throughput revenue from Double Eagle for the year ended December 31, 2015 and 2016 of $3.4 million and $3.3 million, respectively, which we included in transportation and terminals revenue on our consolidated statements of income. At December 31, 2015 and 2016, we recognized $0.2 million and $0.3 million, respectively, of trade accounts receivable from Double Eagle.

We recognized storage revenue of $0.7 million from Saddlehorn for the year ended December 31, 2016, which we included in transportation and terminals revenue on our consolidated statements of income. At December 31, 2016, we recognized a $0.1 million other accounts receivable from Saddlehorn related to miscellaneous cost reimbursements.

The financial results from Texas Frontera are included in our marine storage segment, the financial results from BridgeTex, Double Eagle, HoustonLink, Osage, Saddlehorn and Seabrook are included in our crude oil segment and the financial results from Powder Springs are included in our refined products segment, each as earnings/losses 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, 2015	$ 765,628
Additional investment	200,023
Exchange of investment in non-controlled entity	(25,105)
Earnings of non-controlled entities:	
Proportionate share of earnings	80,974
Amortization of excess investment and capitalized interest	(2,278)
Earnings of non-controlled entities	78,696
Less:	
Distributions of earnings from investments in non-controlled entities	78,723
Distributions in excess of earnings of non-controlled entities	9,264
Investments at December 31, 2016	$ 931,255

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

	December 31, 2015	December 31, 2016
Current assets	$ 158,128	$ 208,901
Noncurrent assets	1,383,394	1,714,920
Total assets	$ 1,541,522	$ 1,923,821
Current liabilities	$ 149,231	$ 111,164
Noncurrent liabilities	7,719	27,022
Total liabilities	$ 156,950	$ 138,186
Equity	$ 1,384,572	$ 1,785,635

	Year Ended December 31, 2014	2015	2016
Revenue	$ 84,056	$ 246,841	$ 279,180
Net income	$ 41,279	$ 138,457	$ 164,684

5. Business Combinations

2015 Business Combination.

On May 1, 2015, we acquired a refined products terminal in Atlanta, Georgia for net cash consideration of $54.7 million. As this acquired business is not significant to our consolidated operating results and financial position, pro forma financial information and the purchase price allocation of acquired assets and liabilities have not been presented. The results of the acquired operations subsequent to the acquisition date have been included in the accompanying consolidated financial statements and in the tables below in our refined products operating segment.

6. Inventory

Inventory at December 31, 2015 and 2016 was as follows (in thousands):

	December 31, 2015	December 31, 2016
Refined products	$ 57,455	$ 54,285
Liquefied petroleum gases	17,954	24,868
Transmix	21,297	28,319
Crude oil	28,385	20,839
Additives	5,777	6,067
Total inventory	$ 130,868	$ 134,378

7. Product Sales Revenue

The amounts reported as product sales revenue on our consolidated statements of income include revenue from the physical sale of petroleum products and mark-to-market adjustments from exchange-based futures contracts. See Note 13 – *Derivative Financial Instruments* for a discussion of our commodity hedging strategies and how our futures contracts impact product sales revenue. All of the petroleum products inventory we physically sell associated with our butane blending and fractionation activities, as well as the barrels from product gains we obtain from our operations, including tender deductions, are reported as product sales revenue on our consolidated statements of income.

For the years ended December 31, 2014, 2015 and 2016, product sales revenue included the following (in thousands):

	Year Ended December 31,		
	2014	2015	2016
Physical sale of petroleum products	$ 733,654	$ 561,410	$ 638,186
Change in value of futures contracts	145,320	68,426	(38,584)
Total product sales revenue	$ 878,974	$ 629,836	$ 599,602

8. Property, Plant and Equipment and Other Intangibles

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

	December 31,		Estimated Depreciable Lives
	2015	2016	
Construction work-in-progress	$ 476,662	$ 500,208	
Land and rights-of-way	275,277	339,561	
Buildings	88,641	101,065	10 to 56 years
Storage tanks	1,684,430	1,829,223	10 to 40 years
Pipeline and station equipment	2,249,067	2,457,429	10 to 69 years
Processing equipment	1,217,492	1,350,032	3 to 56 years
Other	175,197	206,219	3 to 48 years
Property, Plant and Equipment, Gross	$ 6,166,766	$ 6,783,737	

Other includes total interest capitalized on construction in progress as of December 31, 2015 and 2016 of $31.4 million and $43.1 million, respectively. Depreciation expense for the years ended December 31, 2014, 2015 and 2016 was $159.0 million, $164.1 million and $176.7 million, respectively.

We amortize other intangible assets with finite lives over their estimated useful lives of 6 years up to 30 years. The weighted average asset life of our other intangible assets at December 31, 2016 was approximately 21 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, 2014, 2015 and 2016 amortization of other intangible assets was $2.7 million, $2.7 million and $1.4 million, respectively. No material impairments of intangible assets were recorded during these same annual periods.

9. Major Customers and Concentration of Risks

Major Customers. One customer accounted for 12% of our consolidated total revenue in 2014. The majority of these revenues resulted from the sale of refined products that were generated in connection with our butane blending and fractionation activities, which are activities conducted by our refined products segment. No other customer accounted for more than 10% of our consolidated revenues during 2014, 2015 and 2016.

Concentration of Risks. We transport, store and distribute refined products for refiners, marketers, traders and end users of those products. We derive the major concentration of our revenue and trade receivables from activities conducted 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, 2016, we had 1,747 employees, 930 of which were assigned to our refined products segment and concentrated in the central U.S. Approximately 24% of the 930 employees are represented by the United Steel Workers ("USW") and covered by a collective bargaining agreement that expires in January 2019. At December 31, 2016, 141 of our employees were assigned to our crude oil segment and were concentrated in the central U.S., and none of these employees were covered by a collective bargaining agreement. The labor force of 171 employees assigned to our marine storage segment at December 31, 2016 was primarily located in the Gulf and East Coast regions of the U.S. Approximately 17% of these employees are represented by the International Union of Operating Engineers ("IUOE") and covered by a collective bargaining agreement that expires in October 2020.

10. Employee Benefit Plans

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 $8.3 million, $8.9 million and $9.6 million in 2014, 2015 and 2016, respectively.

Additionally, we sponsor two union pension plans that cover certain union employees ("USW plan" and "IUOE plan," collectively, the "Union plans") and a pension plan for all non-union employees ("Salaried plan"), and a postretirement benefit plan for selected 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 for the years ended December 31, 2015 and 2016 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2015	2016	2015	2016
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 190,663	$ 209,591	$ 12,446	$ 11,314
Service cost	18,890	18,179	243	235
Interest cost	7,754	7,950	438	489
Plan participants' contributions	—	—	199	217
Plan amendment	(3,610)	—	—	—
Actuarial loss (gain)	574	1,050	(579)	1,481
Benefits paid	(4,680)	(10,053)	(1,433)	(725)
Settlement payments	—	(747)	—	—
Benefit obligation at end of year	209,591	225,970	11,314	13,011
Change in plan assets:				
Fair value of plan assets at beginning of year	127,267	142,742	—	—
Employer contributions	20,482	25,972	1,234	508
Plan participants' contributions	—	—	199	217
Actual return on plan assets	(327)	8,992	—	—
Benefits paid	(4,680)	(10,053)	(1,433)	(725)
Settlement payments	—	(747)	—	—
Fair value of plan assets at end of year	142,742	166,906	—	—
Funded status at end of year	$ (66,849)	$ (59,064)	$ (11,314)	$ (13,011)
Accumulated benefit obligation	$ 148,906	$ 160,642		

At December 31, 2015, the USW and Salaried plans had a combined accumulated benefit obligation of $146.8 million, which exceeded the combined fair value of the plans' assets of $140.6 million. At December 31, 2016, the fair value of each of our plans' assets exceeded the accumulated benefit obligation of the related benefit plans.

The Salaried and USW plans were amended effective January 1, 2016 to adjust the benefit calculation from a traditional final average pay formula to a cash balance formula for certain participants. We accounted for this change as a negative plan amendment, which resulted in a reduction of our pension liability at December 31, 2015 of $3.6 million.

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

	Pension Benefits		Other Postretirement Benefits	
	2015	2016	2015	2016
Amounts recognized in consolidated balance sheets:				
Current accrued benefit cost	$ —	$ —	$ 612	$ 614
Long-term pension and benefits	66,849	59,064	10,702	12,397
	66,849	59,064	11,314	13,011
Accumulated other comprehensive loss:				
Net actuarial loss	(65,889)	(62,013)	(7,280)	(7,881)
Prior service credit	3,610	3,429	3,335	—
	(62,279)	(58,584)	(3,945)	(7,881)
Net amount of liabilities and accumulated other comprehensive loss recognized in consolidated balance sheets	$ 4,570	$ 480	$ 7,369	$ 5,130

Net periodic benefit expense for the years ended December 31, 2014, 2015 and 2016 were as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2014	2015	2016	2014	2015	2016
Components of net periodic pension and postretirement benefit expense:						
Service cost	$ 13,400	$ 18,890	$ 18,179	$ 227	$ 243	$ 235
Interest cost	6,675	7,754	7,950	506	438	489
Expected return on plan assets	(6,363)	(8,037)	(8,913)	—	—	—
Amortization of prior service cost (credit)	33	—	(181)	(3,713)	(3,713)	(3,335)
Amortization of actuarial loss	3,071	6,306	4,645	915	885	880
Settlement cost	1,809	—	202	—	—	—
Net periodic expense (credit)	$ 18,625	$ 24,913	$ 21,882	$ (2,065)	$ (2,147)	$ (1,731)

Other changes in plan assets and benefit obligations recognized in other comprehensive loss during 2014, 2015 and 2016 were as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2014	2015	2016	2014	2015	2016
Beginning balance	$ (36,184)	$ (63,257)	$ (62,279)	$ 3,053	$ (1,696)	$ (3,945)
Net actuarial gain (loss)	(31,986)	(8,938)	(971)	(1,951)	579	(1,481)
Plan amendment	—	3,610	—	—	—	—
Amortization of prior service cost (credit)	33	—	(181)	(3,713)	(3,713)	(3,335)
Amortization of actuarial loss	3,071	6,306	4,645	915	885	880
Settlement cost	1,809	—	202	—	—	—
Amount recognized in other comprehensive loss	(27,073)	978	3,695	(4,749)	(2,249)	(3,936)
Ending balance	$ (63,257)	$ (62,279)	$ (58,584)	$ (1,696)	$ (3,945)	$ (7,881)

Actuarial gains and losses are amortized over the average future service period of 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 percent 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 2017 are $4.1 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 2017 is $0.8 million.

The weighted-average rate assumptions used to determine benefit obligations as of December 31, 2015 and 2016 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2015	2016	2015	2016
Discount rate—Salaried plan[1]	3.95%	4.21%	n/a	n/a
Discount rate—USW plan	3.82%	4.08%	n/a	n/a
Discount rate—IUOE plan	4.03%	4.41%	n/a	n/a
Discount rate—Other Postretirement Benefits	n/a	n/a	4.00%	3.85%
Rate of compensation increase—Salaried plan[2]	4% - 11%	4% - 11%	n/a	n/a
Rate of compensation increase—USW plan	3.50%	3.50%	n/a	n/a
Rate of compensation increase—IUOE plan	5.00%	5.00%	n/a	n/a

(1)The weighted-average discount rate excludes benefit obligations for which present value calculations are not applicable.

(2)The rate of compensation increase assumption for the Salaried plan is calculated by 10-year age groupings beginning with ages 20-29 at 11% dropping to 4% by ages 70 and above.

The weighted-average rate assumptions used to determine net pension and other postretirement benefit expense for the years ended December 31, 2014, 2015 and 2016 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2014	2015	2016	2014	2015	2016
Discount rate—Salaried plan	4.89%	3.91%	3.95%	n/a	n/a	n/a
Discount rate—USW plan	4.07%	3.56%	3.82%	n/a	n/a	n/a
Discount rate—IUOE plan	4.89%	3.93%	3.78%	n/a	n/a	n/a
Discount rate—Other Postretirement Benefits	n/a	n/a	n/a	4.52%	3.66%	4.00%
Rate of compensation increase—Salaried plan(1)	5.00%	5.50%	4% - 11%	n/a	n/a	n/a
Rate of compensation increase—USW plan	3.50%	3.50%	3.50%	n/a	n/a	n/a
Rate of compensation increase—IUOE plan	5.00%	5.00%	5.00%	n/a	n/a	n/a
Expected rate of return on plan assets—Salaried plan	6.00%	6.00%	6.00%	n/a	n/a	n/a
Expected rate of return on plan assets—USW plan	6.00%	6.00%	6.00%	n/a	n/a	n/a
Expected rate of return on plan assets—IUOE plan	6.00%	6.00%	6.00%	n/a	n/a	n/a

(1)The rate of compensation increase assumption for the Salaried plan in 2016 is calculated by 10-year age groupings beginning with ages 20-29 at 11% dropping to 4% by ages 70 and above.

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 2017 is 5.5% decreasing systematically to 4.5% by 2080 for pre-65 year-old participants. The health care cost trend rate assumption has an effect on the amounts reported. As of December 31, 2016, a 1.0% change in assumed health care cost trend rates would be immaterial to us.

The fair values of the pension plan assets at December 31, 2015 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[a]:				
Small-cap fund	$ 3,492	$ 3,492	$ —	$ —
Mid-cap fund	3,495	3,495	—	—
Large-cap fund	26,304	26,304	—	—
International equity fund	16,530	16,530	—	—
Fixed Income Securities[a]:				
Short-term bond funds	3,834	3,834	—	—
Intermediate-term bond funds	18,141	18,141	—	—
Long-term investment grade bond funds	66,758	66,758	—	—
Other:				
Short-term investment funds	3,944	3,944	—	—
Group annuity contract	244	—	—	244
Fair value of plan assets	$ 142,742	$ 142,498	$ —	$ 244

(a) 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, 2016 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[a]:				
Small-cap fund	$ 3,465	$ 3,465	$ —	$ —
Mid-cap fund	3,472	3,472	—	—
Large-cap funds	26,323	26,323	—	—
International equity fund	16,797	16,797	—	—
Fixed Income Securities[a]:				
Short-term bond funds	4,414	4,414	—	—
Intermediate-term bond funds	23,629	23,629	—	—
Long-term investment grade bond funds	83,240	83,240	—	—
Other:				
Short-term investment fund	5,346	5,346	—	—
Group annuity contract	220	—	—	220
Fair value of plan assets	$ 166,906	$ 166,686	$ —	$ 220

(a) 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 funds	Seek 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 funds	Seek current income with limited price volatility through investment in primarily high quality bonds
Intermediate-term bond funds	Seek 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 of 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 segment liabilities are calculated using rates defined by the Pension Protection Act of 2006. Investments are made so as to match the durations of the short and intermediate term pension liabilities. Additional investments are made to bring the overall investment allocation to 70% fixed income securities and 30% equity securities.

The target allocation and actual weighted-average asset allocation percentages at December 31, 2015 and 2016 were as follows:

	2015		2016	
	Actual	Target	Actual	Target
Equity securities	35%	30%	30%	30%
Fixed income securities	62%	67%	67%	67%
Other	3%	3%	3%	3%

As of December 31, 2016, the benefit amounts expected to be paid from plan assets through December 31, 2026 were as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2017	$ 13,783	$ 614
2018	$ 14,016	$ 685
2019	$ 13,245	$ 778
2020	$ 16,435	$ 857
2021	$ 14,438	$ 933
2022 through 2026	$ 72,826	$ 4,702

Contributions estimated to be paid by us into the plans in 2017 are $22.7 million and $0.5 million for the pension and other postretirement benefit plans, respectively.

11. Related Party Transactions

Barry R. Pearl is an independent member of our general partner's board of directors and was also a director of Targa Resources Partners, L.P. ("Targa") through February 29, 2016. In the normal course of business, we purchase butane from subsidiaries of Targa. During Mr. Pearl's tenure as a director of the general partner of Targa, we made purchases of butane from subsidiaries of Targa of $28.2 million, $25.5 million and $4.7 million for the years ended December 31, 2014, 2015 and 2016, respectively. We had recognized payables to Targa of $2.0 million at December 31, 2015.

Stacy P. Methvin was elected as an independent member of our general partner's board of directors on April 23, 2015 and is also a director of one of our customers. We received tariff revenue of $9.3 million and $16.2 million for the period of April 23, 2015 through December 31, 2015 and the year ended December 31, 2016, respectively, from this customer. We recorded a receivable of $1.3 million and $1.4 million from this customer at December 31, 2015 and 2016, respectively. The tariff revenue we recognized from this customer was in the normal course of business, with rates determined in accordance with published tariffs.

See Note 4 – *Investments in Non-Controlled Entities* for a discussion of transactions with our joint venture affiliates.

12. Debt

Long-term debt at December 31, 2015 and 2016 was as follows (in thousands):

	December 31, 2015	December 31, 2016
Commercial paper	$ 280,000	$ 50,000
5.65% Notes due 2016	250,000	—
6.40% Notes due 2018	250,000	250,000
6.55% Notes due 2019	550,000	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
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
Face value of long-term debt	3,430,000	4,100,000
Unamortized debt issuance costs(1)	(18,672)	(26,948)
Net unamortized debt premium(1)	16,459	6,530
Net unamortized amount of gains from historical fair value hedges(1)	11,835	7,610
Long-term debt, net, including current portion	3,439,622	4,087,192
Less: current portion of long-term debt, net	250,335	—
Long-term debt, net	$ 3,189,287	$ 4,087,192

(1) 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, 2016, maturities of our debt were as follows: $0 in 2017; $250.0 million in 2018; $550.0 million in 2019; $50.0 million in 2020; $550.0 million in 2021; and approximately $2.7 billion thereafter.

2016 Debt Offerings

In September 2016, we issued $500.0 million of our 4.25% notes due 2046 in an underwritten public offering. The notes were issued at 98.762% of par. Net proceeds from this offering were approximately $488.5 million, after underwriting discounts and offering expenses of $5.3 million. The net proceeds from this offering were used to repay our $250.0 million of 5.65% notes due October 15, 2016 and to repay borrowings outstanding under our commercial paper program. The remaining proceeds were used for general partnership purposes, including capital expenditures.

In February 2016, we issued $650.0 million of our 5.00% notes due 2026 in an underwritten public offering. The notes were issued at 99.875% of par. Net proceeds from this offering were approximately $643.8 million, after underwriting discounts and offering expenses of $5.4 million. The net proceeds from this offering were used to repay borrowings outstanding under our commercial paper program and for general partnership purposes, including expansion capital.

Other Debt

Revolving Credit Facilities. At December 31, 2016, the total borrowing capacity under our revolving credit facility maturing October 27, 2020 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, 2016. Borrowings under this facility may be used for general purposes, including capital expenditures. As of December 31, 2015 and 2016, respectively, there were no borrowings outstanding under this facility, with $6.3 million obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets, but decrease our borrowing capacity under the facility.

In October 2016, we amended our $250.0 million 364-day revolving credit facility to extend the maturity date to October 19, 2017. Any borrowings under this facility are classified as current debt on our consolidated balance sheets. Borrowings under this 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 between 0.080% and 0.225% depending on our credit ratings. The unused commitment fee was 0.100% at December 31, 2016. Borrowings under this facility may be used for general purposes, including capital expenditures. As of December 31, 2016, there were no borrowings outstanding under this facility.

Our revolving credit facilities require 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 facilities 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, 2016.

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 0.5% and 0.8%, respectively, for the year ended December 31, 2015 and 2016.

During the years ending December 31, 2014, 2015 and 2016, total cash payments for interest on all indebtedness, excluding the impact of related interest rate swap agreements, were $149.5 million, $156.6 million and $181.7 million, respectively.

13. Derivative Financial Instruments

Interest Rate Derivatives

We periodically enter into interest rate derivatives to hedge the fair value of debt or hedge against variability in interest rates, and we have historically designated these derivatives as fair value or cash flow hedges for accounting purposes. Adjustments resulting from discontinued hedges continue to be recognized in accordance with their historic hedging relationships.

During 2016, we entered into $100.0 million of forward-starting interest rate swap agreements to hedge against the risk of variability of future interest payments on a portion of debt we anticipate issuing in 2018. The fair values of these contracts at December 31, 2016 were recorded on our balance sheets as other noncurrent assets of $14.1 million, with the net offset recorded to other comprehensive income. We account for these agreements as cash flow hedges.

During 2015 and 2016, we entered into $250.0 million of forward-starting interest rate swap agreements to hedge against the risk of variability of future interest payments on a portion of debt we anticipated issuing in 2016. We accounted for these agreements as cash flow hedges. When we issued $500.0 million of 4.25% notes due 2046 in third quarter 2016, we settled the associated interest rate swap agreements for a loss of $19.3 million. The loss was recorded to other comprehensive income and will be recognized into earnings as an adjustment to our periodic interest expense accruals over the first ten years of the associated notes. This loss was also reported as a net payment on financial derivatives in the financing activities of our consolidated statements of cash flows in 2016.

During 2014, we entered into $250.0 million of forward-starting interest rate swap agreements to hedge against the risk of variability of future interest payments on a portion of debt we anticipated issuing in 2015. We accounted for these agreements as cash flow hedges. When we issued the $250.0 million of 4.20% notes due 2045 in first quarter 2015, we settled the associated interest rate swap agreements for a loss of $42.9 million. The loss was recorded to other comprehensive income and will be recognized into earnings as an adjustment to our periodic interest expense accruals over the life of the associated notes. This loss was also reported as a net payment on financial derivatives in the financing activities of our consolidated statements of cash flows in 2015.

Also during 2014, we entered into $200.0 million of interest rate swap agreements to hedge against the variability of future interest payments on an anticipated debt issuance. We accounted for these agreements as cash flow hedges. When we issued $250.0 million of 5.15% notes due 2043 later in the first quarter of 2014, we settled the associated interest rate swap agreements for a loss of $3.6 million. The loss was recorded to other comprehensive income and is being recognized into earnings as an adjustment to our periodic interest expense accruals over the life of the associated notes. This loss was also reported as net payment on financial derivatives in the financing activities of our consolidated statements of cash flows in 2014.

Commodity Derivatives

Hedging Strategies

Our butane blending activities produce gasoline products, 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 butane 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.

We account for the forward physical purchase and sale contracts we use in our butane blending and fractionation activities as normal purchases and sales. Forward contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting.

The futures contracts that we enter into fall into one of three hedge categories:

Hedge Type	Hedge Purpose	Accounting Treatment
Qualifies for Hedge Accounting Treatment		
Cash Flow Hedge	To hedge the variability in cash flows related to a forecasted transaction.	The effective portion of changes in the fair value of the hedge is recorded to accumulated other comprehensive income/loss and reclassified to earnings when the forecasted transaction occurs. Any ineffectiveness is recognized currently in earnings.
Fair Value Hedge	To hedge against changes in the fair value of a recognized asset or liability.	The effective portion of changes in the fair value of the hedge is recorded as adjustments to the asset or liability being hedged. Any ineffectiveness and amounts excluded from the assessment of hedge effectiveness is recognized currently in earnings.
Does not Qualify For Hedge Accounting Treatment		
Economic Hedge	To effectively serve as either a fair value or a cash flow hedge; however, the derivative agreement does not qualify for hedge accounting treatment under ASC 815, *Derivatives and Hedging*.	Changes in the fair value of these agreements are recognized currently in earnings.

During the years ended December 31, 2015 and 2016, none of the commodity hedging contracts we entered into qualified for or were designated as cash flow hedges.

We use futures contracts designated as economic hedges for accounting purposes to hedge against changes in the price of refined products and crude oil that we expect to sell in the future. Period changes in the fair value of these agreements are recognized currently in earnings as adjustments to product sales.

We also use futures contracts designated as economic hedges for accounting purposes to hedge against changes in the price of butane we expect to purchase in the future. Period changes in the fair value of these agreements are recognized currently in earnings as adjustments to cost of product sales.

We hold petroleum product inventories that we obtain from overages on our pipeline systems. We use futures contracts that are designated as economic hedges for accounting purposes to help manage price changes related to these inventory barrels. Period changes in the fair value of these agreements are recognized currently in earnings as adjustments to operating expense.

Additionally, we hold certain crude oil tank bottoms which we classify as long-term assets and include with other noncurrent assets on our consolidated balance sheets. We use futures contracts to hedge against changes in the fair value of these assets. We record the effective portion of the gains or losses for those contracts that qualify as fair value hedges as adjustments to the asset being hedged and the ineffective portions as well as amounts excluded from the assessment of hedge effectiveness as adjustments to other income or expense.

As outlined in the table below, our open futures contracts at December 31, 2016 were as follows:

Type of Contract/Accounting Methodology	Product Represented by the Contract and Associated Barrels	Maturity Dates
Futures - Fair Value Hedges	0.7 million barrels of crude oil	November 2017
Futures - Economic Hedges	3.9 million barrels of refined products and crude oil	Between January and April 2017
Futures - Economic Hedges	0.7 million barrels of butane	Between January and April 2017

Energy Commodity Derivatives Contracts and Deposits Offsets

At December 31, 2016, we had made margin deposits of $49.9 million for our futures contracts with our counterparties, which were recorded as a current asset under energy commodity derivatives deposits on our consolidated balance sheets. At December 31, 2015, we had received margin deposits of $24.3 million which were recorded as a current liability under energy 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, 2015 and 2016 (in thousands):

	December 31, 2015				
Description	Gross Amounts of Recognized Assets	Gross Amounts of Liabilities Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets(1)	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheets	Net Asset Amount(2)
Energy commodity derivatives	$ 48,367	$ (5,646)	$ 42,721	$ (24,252)	$ 18,469

	December 31, 2016				
Description	Gross Amounts of Recognized Liabilities	Gross Amounts of Assets Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheets	Net Asset Amount(2)
Energy commodity derivatives	$ (36,798)	$ 6,060	$ (30,738)	$ 49,899	$ 19,161

(1) Net amount includes energy commodity derivative contracts classified as current assets, net of $39,243 and noncurrent assets of $3,478.

(2) This represents the maximum amount of loss we would incur if our counterparties failed to perform on their derivative contracts.

Impact of Derivatives on Our Financial Statements

Comprehensive Income

The changes in derivative activity included in AOCL for the years ended December 31, 2014, 2015 and 2016 were as follows (in thousands):

Derivative Gains (Losses) Included in AOCL	Year Ended December 31, 2014	2015	2016
Beginning balance	$ 13,627	$ (16,587)	$ (30,126)
Net loss on interest rate contract cash flow hedges	(30,090)	(14,904)	(6,699)
Reclassification of net loss (gain) on cash flow hedges to income	(124)	1,365	2,049
Ending balance	$ (16,587)	$ (30,126)	$ (34,776)

The following is a summary of the effect on our consolidated statements of income for the years ended December 31, 2014, 2015 and 2016 of derivatives accounted for under ASC 815-30, *Derivatives and Hedging—Cash Flow Hedges*, that were designated as hedging instruments (in thousands).

	Year Ended December 31, 2014			
			Amount of Gain (Loss) Reclassified from AOCL into Income	
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Gain (Loss) Reclassified from AOCL into Income	Effective Portion	Ineffective Portion
Interest rate contracts	$ (30,090)	Interest expense	$ (242)	$ 366

	Year Ended December 31, 2015			
			Amount of Loss Reclassified from AOCL into Income	
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Loss Reclassified from AOCL into Income	Effective Portion	Ineffective Portion
Interest rate contracts	$ (14,904)	Interest expense	$ (1,365)	$ —

	Year Ended December 31, 2016			
			Amount of Loss Reclassified from AOCL into Income	
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Loss Reclassified from AOCL into Income	Effective Portion	Ineffective Portion
Interest rate contracts	$ (6,699)	Interest expense	$ (2,049)	$ —

As of December 31, 2016, the net loss estimated to be classified to interest expense over the next twelve months from AOCL is approximately $3.0 million. This amount relates to the amortization of the hedged losses on the interest rate swap contracts over the life of the related debt instruments.

We use futures contracts designated as fair value hedges under ASC 815-25, *Derivatives and Hedging—Fair Value Hedges,* to hedge against changes in the fair value of 0.7 million barrels of crude oil that are contractually reserved as tank bottoms and included with other noncurrent assets on our consolidated balance sheets. The effective portions of the fair value gains or losses on these futures contracts were offset by fair value gains or losses on the tank bottoms. There was no ineffectiveness recognized on these hedges. The cash flows from settled contracts were recorded in operating activities in our consolidated statements of cash flows. The gains (losses) on these futures contracts and the underlying tank bottoms were as follows (in millions):

	Year Ended December 31,		
	2014	2015	2016
Gain (loss) recognized in other income/expense on derivative (futures contracts)	$ 13.5	$ 15.6	$ (9.0)
Gain (loss) recognized in other income/expense on hedged item (tank bottoms)	$ (13.5)	$ (15.6)	$ 9.0

The differential between the current spot price and forward price is excluded from the assessment of hedge effectiveness for these fair value hedges. During 2014, 2015 and 2016, we recognized a gain (loss) of $(8.6) million, $1.0 million and $5.2 million, respectively, for the amounts we excluded from the assessment of effectiveness of these fair value hedges, which we reported as other income/expense on our consolidated statements of income.

The following table provides a summary of the effect on our consolidated statements of income for the years ended December 31, 2014, 2015 and 2016 of derivatives accounted for under ASC 815, *Derivatives and Hedging*, 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 Derivative	2014	2015	2016
Futures contracts	Product sales revenue	$ 145,320	$ 68,426	$ (38,584)
Futures contracts	Operating expenses	17,818	11,819	(5,000)
Futures contracts	Cost of product sales	(17,141)	(8,997)	10,998
	Total	$ 145,997	$ 71,248	$ (32,586)

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 tables provide a summary of the fair value of derivatives accounted for under ASC 815, *Derivatives and Hedging*, which are presented on a net basis in our consolidated balance sheets, that were designated as hedging instruments as of December 31, 2015 and 2016 (in thousands):

	December 31, 2015			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Energy commodity derivatives contracts, net	$ 60	Energy commodity derivatives contracts, net	$ —
Futures contracts	Other noncurrent assets	3,478	Other noncurrent liabilities	—
Interest rate contracts	Other current assets	2,179	Other current liabilities	653
	Total	$ 5,717	Total	$ 653

	December 31, 2016			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Energy commodity derivatives contracts, net	$ —	Energy commodity derivatives contracts, net	$ 3,079
Interest rate contracts	Other noncurrent assets	14,114	Other noncurrent liabilities	—
	Total	$ 14,114	Total	$ 3,079

The following tables provide a summary of the fair value of derivatives accounted for under ASC 815, *Derivatives and Hedging*, which are presented on a net basis in our consolidated balance sheets, that were not designated as hedging instruments as of December 31, 2015 and 2016 (in thousands):

	December 31, 2015			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Energy commodity derivatives contracts, net	$ 44,829	Energy commodity derivatives contracts, net	$ 5,646

	December 31, 2016			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Energy commodity derivatives contracts, net	$ 6,060	Energy commodity derivatives contracts, net	$ 33,719

See Note 19 – *Fair Value Disclosures* for additional details regarding our derivative contracts.

14. Leases

Leases—Lessee. We lease office buildings, terminal equipment and pipeline capacity (primarily to facilitate movements on our Longhorn pipeline and Little Rock pipeline extension) to conduct our business operations. We have also entered into land leases and right-of-way contracts, several of which have cancellation penalties that include the requirement to remove our pipeline from the property for non-performance. Several of our agreements provide for negotiated renewal options, and management expects that we will generally renew our expiring leases.

Leases are evaluated at inception or at any subsequent material modification and, depending on the lease terms, are classified as either capital or operating leases, as appropriate under ASC 840, *Leases*. We recognize rent expense on a straight-line basis over the life of the lease. Total rent expense was $21.0 million, $25.7 million and $30.2 million for the years ended December 31, 2014, 2015 and 2016, respectively. Future minimum annual rentals under non-cancellable operating leases with initial or remaining terms greater than one year as of December 31, 2016, were as follows (in millions):

2017	$ 38.6
2018	32.9
2019	21.1
2020	17.8
2021	17.4
Thereafter	110.6
Total	$ 238.4

Leases—Lessor. We have entered into capacity leases and storage contracts with our customers with remaining terms from one to approximately 20 years that are accounted for as operating-type leases. All of the agreements provide for negotiated extensions. Future minimum payments receivable under these arrangements as of December 31, 2016, were as follows (in millions):

2017	$ 227.6
2018	208.7
2019	158.8
2020	109.6
2021	77.0
Thereafter	188.5
Total	$ 970.2

Direct Financing Lease. We entered into a long-term throughput and deficiency agreement with a customer on a 40-mile pipeline we constructed in Texas and New Mexico, which contains minimum volume/payment commitments. This agreement is being accounted for as a direct financing lease. The net investment under direct financing leasing arrangements as of December 31, 2015 and 2016 was as follows (in millions):

	December 31, 2015	December 31, 2016
Total minimum lease payments receivable	$ 30.7	$ 23.3
Less: Unearned income	5.8	4.8
Recorded net investment in direct financing lease	$ 24.9	$ 18.5

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

	December 31, 2015	December 31, 2016
Other accounts receivable	$ 6.4	$ 3.4
Long-term receivables	18.5	15.1
Total	$ 24.9	$ 18.5

Future minimum payments receivable under this direct financing lease for the next five years are: 2017 – $4.1 million; 2018 – $1.7 million; 2019 – $1.7 million; 2020 – $1.7 million; and 2021 – $1.7 million.

15. Long-Term Incentive Plan

Plan Description

We have a long-term incentive plan ("LTIP") covering certain of our employees and 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 limited partner units. The estimated units remaining available under the LTIP at December 31, 2016 total approximately 3.0 million. The compensation committee of our general partner's board of directors administers our LTIP.

Under our LTIP, the compensation committee has granted performance-based and time-based phantom unit awards. Time-based awards are subject to forfeiture by a participant if their employment is terminated for any reason other than retirement, death or disability prior to the vesting date. In addition, there are certain other employment restrictions that can result in the forfeiture of these awards. Performance-based awards are subject to forfeiture by a participant if their employment is terminated for any reason other than for a 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. If a performance-based or time-based award recipient retires, dies or becomes disabled prior to the end of the vesting period, the recipient's award will be prorated based upon the completed months of employment during the vesting period, and the award will be settled shortly after the end of the vesting period. Our agreement with the LTIP participants requires these awards to be paid in our limited partner units. Performance-based awards granted under our LTIP can vest early under certain circumstances following a change in control of our general partner.

The payouts for the performance-based phantom unit awards issued in 2014, 2015 and 2016 are each subject to the attainment of a financial metric and market performance adjustments. The payout of the performance-based awards is based on our distributable cash flow excluding commodity-related activities for the last year of each of the 3-year vesting periods as compared against established threshold, target and stretch goals. The payouts for the performance-related component of the awards can range from 0% for below threshold results, up to 200% for actual results at stretch or above. The market performance adjustment component of the awards is based on our total unitholder return over the 3-year vesting period of the awards in relation to the total unitholder returns of certain peer entities and can increase or decrease the calculated performance-based payout of the award by as much as 50%. These awards are classified as equity awards.

The payout for the time-based phantom unit awards that have been granted by the compensation committee is subject only to the participant's continued employment with us. These awards are classified as equity awards.

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 - 1/1/2016	313,240	$	79.64	57,682	$	81.74	370,922	$	79.97
Units granted during 2016	193,344	$	70.29	39,301	$	64.76	232,645	$	69.35
Units vested during 2016	(163,632)	$	72.32	(9,511)	$	71.40	(173,143)	$	72.27
Units forfeited during 2016	(29,256)	$	76.08	(5,054)	$	73.20	(34,310)	$	75.66
Non-vested units - 12/31/16	313,696	$	78.03	82,418	$	75.36	396,114	$	77.47

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:						
2015 Awards	131,335	32,834	164,169	12/31/2017	$	4.8
2016 Awards	182,361	—	182,361	12/31/2018		8.5
Time-Based Awards:						
2017 Vesting Date	50,488	—	50,488	12/31/2017		1.5
2018 Vesting Date	30,456	—	30,456	12/31/2018		1.3
2020 Vesting Date	1,474	—	1,474	12/31/2020		0.1
Total	396,114	32,834	428,948		$	16.2

(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 issued during 2014, 2015 and 2016 were 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 2014	187,371	$	72.77	33,903	$	82.86
Units granted during 2015	148,028	$	88.78	26,421	$	81.51
Units granted during 2016	193,344	$	70.29	39,301	$	64.76

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, 2016. The vested limited partner units include adjustments for above-target financial and market performance.

Vesting Date	Vested Limited Partner Units	Fair Value of Unit Awards on Vesting Date (in millions)	Intrinsic Value of Unit Awards on Vesting Date (in millions)
12/31/2014	528,984	$22.4	$43.7
12/31/2015	506,393	$27.7	$34.4
12/31/2016	361,711	$22.6	$27.4

Cash Flow Effects of LTIP Settlements

We settle awards that vest by issuing limited partner units. The difference between the limited partner units issued to the participants and the total units accrued represents the minimum tax withholdings associated with the award settlement, which we pay in cash.

Settlement Date	Number of Limited Partner Units Issued, Net of Tax Withholdings	Minimum Tax Withholdings (in millions)	Employer Taxes (in millions)	Total Cash Taxes Paid (in millions)
January 2014	387,216	$14.8	$1.2	$16.0
January 2015	354,529	$17.8	$1.7	$19.5
February 2016	350,552	$14.4	$1.4	$15.8

Compensation Expense Summary

Equity-based incentive compensation expense for 2014, 2015 and 2016 was as follows (in thousands):

	Year Ended December 31,		
	2014	2015	2016
2012 awards	$ 8,314	$ —	$ —
2013 awards	10,852	10,658	—
2014 awards	6,494	7,471	7,928
2015 awards	—	4,917	4,874
2016 awards	—	—	4,304
Time-based awards	1,624	1,199	2,252
Total	$ 27,284	$ 24,245	$ 19,358
Allocation of LTIP expense on our consolidated statements of income:			
G&A expense	$ 26,700	$ 23,937	$ 19,204
Operating expense	584	308	154
Total	$ 27,284	$ 24,245	$ 19,358

16. 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 and amortization expense and G&A expense that management does not consider when evaluating the core profitability of our separate operating segments.

	Year Ended December 31, 2014 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	$ 946,612	$ 341,915	$ 170,740	$ —	$ 1,459,267
Product sales revenue	872,537	—	6,437	—	878,974
Affiliate management fee revenue	—	20,790	1,321	—	22,111
Total revenue	1,819,149	362,705	178,498	—	2,360,352
Operating expenses	356,057	83,184	65,173	(3,513)	500,901
Cost of product sales	592,887	—	1,698	—	594,585
(Earnings) loss of non-controlled entities	—	(16,309)	(3,085)	—	(19,394)
Operating margin	870,205	295,830	114,712	3,513	1,284,260
Depreciation and amortization expense	101,642	27,800	28,786	3,513	161,741
G&A expenses	96,411	29,557	22,320	—	148,288
Operating profit	$ 672,152	$ 238,473	$ 63,606	$ —	$ 974,231
Additions to long-lived assets	$ 163,753	$ 439,846	$ 18,413		$ 622,012
	As of December 31, 2014				
Segment assets	$ 2,875,412	$ 1,937,242	$ 647,900		$ 5,460,554
Corporate assets					40,855
Total assets					$ 5,501,409
Goodwill	$ 38,369	$ 12,082	$ 2,809		$ 53,260
Investments in non-controlled entities	$ —	$ 599,757	$ 14,110		$ 613,867

	Year Ended December 31, 2015 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	$ 974,505	$ 394,098	$ 176,143	$ —	$ 1,544,746
Product sales revenue	623,102	3,587	3,147	—	629,836
Affiliate management fee revenue	—	12,495	1,376	—	13,871
Total revenue	1,597,607	410,180	180,666	—	2,188,453
Operating expenses	377,772	89,455	62,526	(3,851)	525,902
Cost of product sales	442,621	3,278	1,374	—	447,273
(Earnings) loss of non-controlled entities	193	(63,918)	(2,758)	—	(66,483)
Operating margin	777,021	381,365	119,524	3,851	1,281,761
Depreciation and amortization expense	96,244	35,681	31,036	3,851	166,812
G&A expenses	94,482	36,000	20,847	—	151,329
Operating profit	$ 586,295	$ 309,684	$ 67,641	$ —	$ 963,620
Additions to long-lived assets	$ 310,907	$ 289,851	$ 70,290		$ 671,048
	As of December 31, 2015				
Segment assets	$ 2,991,322	$ 2,313,110	$ 677,914		$ 5,982,346
Corporate assets					59,221
Total assets					$ 6,041,567
Goodwill	$ 38,369	$ 12,082	$ 2,809		$ 53,260
Investments in non-controlled entities	$ 12,381	$ 739,470	$ 13,777		$ 765,628

	Year Ended December 31, 2016 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	$ 1,002,368	$ 407,837	$ 181,721	$ (807)	$ 1,591,119
Product sales revenue	561,759	31,170	6,673	—	599,602
Affiliate management fee revenue	765	12,533	1,391	—	14,689
Total revenue	1,564,892	451,540	189,785	(807)	2,205,410
Operating expenses	381,055	88,762	65,704	(5,762)	529,759
Cost of product sales	459,989	31,657	1,692	—	493,338
(Earnings) loss of non-controlled entities	968	(76,972)	(2,692)	—	(78,696)
Operating margin	722,880	408,093	125,081	4,955	1,261,009
Depreciation and amortization expense	103,388	38,081	31,718	4,955	178,142
G&A expenses	91,795	36,305	19,715	—	147,815
Operating profit	$ 527,697	$ 333,707	$ 73,648	$ —	$ 935,052
Additions to long-lived assets	$ 291,202	$ 250,433	$ 104,728		$ 646,363
	As of December 31, 2016				
Segment assets	$ 3,289,600	$ 2,631,407	$ 791,132		$ 6,712,139
Corporate assets					59,934
Total assets					$ 6,772,073
Goodwill	$ 38,369	$ 12,082	$ 2,809		$ 53,260
Investments in non-controlled entities	$ 31,029	$ 886,920	$ 13,306		$ 931,255

17. Commitments and Contingencies

Environmental Liabilities

Liabilities recognized for estimated environmental costs were $31.4 million and $24.0 million at December 31, 2015 and December 31, 2016, respectively. We have classified environmental liabilities as 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 $5.0 million, $8.4 million and $5.9 million for the years ended December 31, 2014, 2015 and 2016, respectively.

Environmental Receivables

Receivables from insurance carriers and other third parties related to environmental matters at December 31, 2015 were $2.6 million, of which $0.7 million and $1.9 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, 2016 were $4.1 million, of which $0.6 million and $3.5 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 2014, 2015 and 2016 were $0.5 million, $0.5 million and $0.9 million, respectively.

Other

We are a party to various other claims, legal actions and complaints arising in the ordinary course of business, including without limitation those disclosed in Item 3. *Legal Proceedings* of Part I of this 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.

18. Quarterly Financial Data (unaudited)

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

2015	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$ 530,302	$ 498,427	$ 586,676	$ 573,048
Total costs and expenses	$ 320,081	$ 315,206	$ 312,527	$ 343,502
Operating margin	$ 297,006	$ 286,145	$ 369,325	$ 329,285
Net income	$ 183,636	$ 177,391	$ 250,972	$ 207,123
Basic net income per limited partner unit	$ 0.81	$ 0.78	$ 1.10	$ 0.91
Diluted net income per limited partner unit	$ 0.81	$ 0.78	$ 1.10	$ 0.91
2016				
Revenue	$ 519,816	$ 518,897	$ 551,782	$ 614,915
Total costs and expenses	$ 321,446	$ 307,709	$ 336,409	$ 383,490
Operating margin	$ 300,626	$ 304,371	$ 316,830	$ 339,182
Net income	$ 207,070	$ 187,859	$ 194,551	$ 213,291
Basic net income per limited partner unit	$ 0.91	$ 0.82	$ 0.85	$ 0.94
Diluted net income per limited partner unit	$ 0.91	$ 0.82	$ 0.85	$ 0.93

19. 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:

- *Energy 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 market 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.

- *Long-term receivables.* These primarily include payments receivable under a direct-financing 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.

- *Debt.* The fair value of our publicly traded notes was based on the prices of those notes at December 31, 2015 and 2016; 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, 2015 and 2016, based on the three levels established by ASC 820; *Fair Value Measurements and Disclosures* (in thousands):

			Fair Value Measurements as of December 31, 2015 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)**
Energy commodity derivatives contracts	$ 42,721	$ 42,721	$ 42,721	$ —	$ —
Interest rate contracts	$ 1,526	$ 1,526	$ —	$ 1,526	$ —
Long-term receivables	$ 20,374	$ 20,374	$ —	$ —	$ 20,374
Debt	$ (3,439,622)	$ (3,284,791)	$ —	$ (3,284,791)	$ —

			Fair Value Measurements as of December 31, 2016 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)**
Energy commodity derivatives contracts	$ (30,738)	$ (30,738)	$ (30,738)	$ —	$ —
Interest rate contracts	$ 14,114	$ 14,114	$ —	$ 14,114	$ —
Long-term receivables	$ 23,870	$ 23,870	$ —	$ —	$ 23,870
Debt	$ (4,087,192)	$ (4,262,321)	$ —	$ (4,262,321)	$ —

20. Distributions

Distributions we paid during 2014, 2015 and 2016 were as follows (in thousands, except per unit amount):

Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution
2/14/2014	$ 0.5850	$ 132,835
5/15/2014	0.6125	139,079
8/14/2014	0.6400	145,324
11/14/2014	0.6675	151,568
Total	$ 2.5050	$ 568,806
2/13/2015	$ 0.6950	$ 158,061
5/15/2015	0.7175	163,178
8/14/2015	0.7400	168,296
11/13/2015	0.7625	173,413
Total	$ 2.9150	$ 662,948
2/12/2016	$ 0.7850	$ 178,808
5/13/2016	0.8025	182,797
8/12/2016	0.8200	186,783
11/14/2016	0.8375	190,769
Total	$ 3.2450	$ 739,157

21. Partners' Capital

The following table details the changes in the number of our limited partner units outstanding from January 1, 2014 through December 31, 2016:

Limited partner units outstanding on January 1, 2014	**226,679,438**
02/2014—Settlement of 2011 awards	387,216
During 2014—Other[(a)]	1,603
Limited partner units outstanding on December 31, 2014	**227,068,257**
01/2015—Settlement of 2012 awards	354,529
During 2015—Other[(a)]	4,461
Limited partner units outstanding on December 31, 2015	**227,427,247**
02/2016—Settlement of 2013 awards	350,552
During 2016—Other[(a)]	6,117
Limited partner units outstanding on December 31, 2016	**227,783,916**

(a) Limited partner 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 the limited partners.

Limited partners holding our limited partner units 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 limited partner unit ownership to substitute limited partners;
- 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 limited partners' 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 unitholders' 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 partners in proportion to the positive balances in their respective capital accounts. The limited partners' liability is generally limited to their investment.

22. Subsequent Events

Recognizable events

No recognizable events have occurred subsequent to December 31, 2016.

Non-recognizable events

On January 31, 2017, we issued 240,640 limited partner units, of which 216,679 were issued to settle unit awards to certain employees that vested on December 31, 2016 and 23,961 were issued to settle the equity-based retainers paid to certain independent directors of our general partner and the final payment of deferred director compensation to a former director.

On February 2, 2017, 207,445 phantom unit awards were issued pursuant to our LTIP. These grants included both performance-based and time-based phantom unit awards and have a 3-year vesting period that will end on December 31, 2019.

On February 14, 2017, we paid cash distributions of $0.855 per unit on our outstanding limited partner units to unitholders of record at the close of business on February 3, 2017. The total distributions paid were $195.0 million.

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

None.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

We performed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rule 13a-14(c) of the Securities Exchange Act) as of the end of the period covered by the date of this report. We performed this evaluation under the supervision and with the participation of our management, including our general partner's Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner's Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and practices are effective in providing reasonable assurance that all required disclosures are included in the current report. There have been no changes in our internal control over financial reporting (as defined in Rule 13a - 15(f) of the Securities Exchange Act) during the quarter ending December 31, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Our management, including our general partner's Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls or our internal controls over financial reporting will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that simple errors or mistakes can occur. Additionally, the individual acts of some persons, collusion by two or more people or management override can circumvent controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our disclosure and internal controls and make modifications as necessary; our intent in this regard is to maintain the disclosure and internal controls as systems change and conditions warrant.

Management's Report on Internal Control Over Financial Reporting

See "Management's Annual Report on Internal Control Over Financial Reporting" set forth in Item 8. Financial Statements and Supplementary Data.

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information regarding the directors and executive officers of our general partner and our corporate governance required by Items 401, 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K will be presented in our definitive proxy statement to be filed pursuant to Regulation 14A (our "Proxy Statement") under the following captions, which information is to be incorporated by reference herein:

- Director Election Proposal;
- Executive Officers of our General Partner;
- Section 16(a) Beneficial Ownership Reporting Compliance;
- Code of Ethics;
- Corporate Governance – Director Nominations; and
- Corporate Governance – Board Committees.

Item 11. ***Executive Compensation***

The information regarding executive compensation required by Items 402 and 407(e)(4) and (e)(5) of Regulation S-K will be presented in our Proxy Statement under the following captions, which information is to be incorporated by reference herein:

- Compensation of Directors and Executive Officers;
- Compensation Committee Interlocks and Insider Participation; and
- Compensation of Directors and Executive Officers – Compensation Committee Report.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information regarding securities authorized for issuance under equity compensation plans and security ownership required by Items 201(d) and 403 of Regulation S-K will be presented in our Proxy Statement under the following captions, which information is to be incorporated by reference herein:

- Securities Authorized for Issuance Under Equity Compensation Plans; and
- Security Ownership of Certain Beneficial Owners and Management.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information regarding certain relationships and related transactions and director independence required by Items 404 and 407(a) of Regulation S-K will be presented in our Proxy Statement under the following captions, which information is to be incorporated by reference herein:

- Transactions with Related Persons, Promoters and Certain Control Persons; and
- Corporate Governance – Director Independence.

Item 14. ***Principal Accountant Fees and Services***

The information regarding principal accountant fees and services required by Item 9(e) of Schedule 14A of the Exchange Act will be presented in our Proxy Statement under the caption "Ratification of Appointment of Independent Auditor Proposal," which information is to be incorporated by reference herein.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a)1 and (a)2.

We have omitted all other required schedules since the required information is not present or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and notes thereto.

(a)3, (b) and (c). The exhibits listed below are filed as part of this annual report.

Exhibit No.	Description
Exhibit 3	
*(a)	Certificate of Limited Partnership of Magellan Midstream Partners, L.P. dated August 30, 2000, as amended on November 15, 2002 and August 12, 2003 (filed as Exhibit 3.1 to Form 10-Q filed November 10, 2003).
*(b)	Fifth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated September 28, 2009 (filed as Exhibit 3.1 to Form 8-K filed September 30, 2009).
*(c)	Amendment No. 1 dated October 27, 2011 to Fifth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated September 28, 2009 (filed as Exhibit 3.1 to Form 8-K filed October 28, 2011).
*(d)	Amendment No. 2 dated January 16, 2017 to Fifth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated September 28, 2009 (filed as Exhibit 3.2 to Form 8-K filed January 17, 2017).
*(e)	Amended and Restated Certificate of Formation of Magellan GP, LLC dated November 15, 2002, as amended on August 12, 2003 (filed as Exhibit 3(f) to Form 10-K filed March 10, 2004).
*(f)	Third Amended and Restated Limited Liability Company Agreement of Magellan GP, LLC dated September 28, 2009 (filed as Exhibit 3.2 to Form 8-K filed September 30, 2009).
*(g)	Amendment No. 1 dated January 16, 2017 to Third Amended and Restated Limited Liability Company Agreement of Magellan GP, LLC dated September 28, 2009 (filed as Exhibit 3.1 to Form 8-K filed January 17, 2017).
Exhibit 4	
*(a)	Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed May 25, 2004).
*(b)	Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed April 20, 2007).
*(c)	First Supplemental Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed April 20, 2007).
*(d)	Second Supplemental Indenture dated as of July 14, 2008 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed July 14, 2008).
*(e)	Third Supplemental Indenture dated as of June 26, 2009 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed June 26, 2009).

Exhibit No.	Description
*(f)	Indenture dated as of August 11, 2010 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed August 16, 2010).
*(g)	First Supplemental Indenture dated as of August 11, 2010 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed August 16, 2010).
*(h)	Second Supplemental Indenture dated as of November 9, 2012 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed November 9, 2012).
*(i)	Third Supplemental Indenture dated as of October 10, 2013 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed October 10, 2013).
*(j)	Fourth Supplemental Indenture dated as of March 4, 2015 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed March 4, 2015).
*(k)	Fifth Supplemental Indenture dated as of March 4, 2015 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.3 to Form 8-K filed March 4, 2015).
*(l)	Sixth Supplemental Indenture dated as of February 29, 2016 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed February 29, 2016).
*(m)	Seventh Supplemental Indenture dated as of September 13, 2016 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed September 13, 2016).
Exhibit 10	
*(a)	Amended and Restated Magellan Midstream Partners Long-Term Incentive Plan dated January 26, 2016 (filed as Exhibit 10(a) to Form 10-K filed February 19, 2016).
(b)	Description of Magellan 2017 Annual Incentive Program.
(c)	Magellan GP, LLC Non-Management Director Compensation Program effective January 1, 2017.
*(d)	Amended and Restated Director Deferred Compensation Plan effective January 28, 2014 (filed as Exhibit 10(d) to Form 10-K filed February 24, 2014).
*(e)	$1,000,000,000 Amended and Restated Credit Agreement dated as of October 27, 2015 among Magellan Midstream Partners, L.P., the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent and an Issuing Bank, JPMorgan Chase Bank, N.A., as Co-Syndication Agent and an Issuing Bank, and SunTrust Bank, as Co-Syndication Agent and an Issuing Bank (filed as Exhibit 10.1 to Form 8-K filed October 28, 2015).
*(f)	$250,000,000 364-Day Credit Agreement dated as of October 27, 2015 among Magellan Midstream Partners, L.P., the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Co-Syndication Agent, and SunTrust Bank, as Co-Syndication Agent (filed as Exhibit 10.2 to Form 8-K filed October 28, 2015).
*(g)	First Amendment to 364-Day Credit Agreement dated as of October 20, 2016 among Magellan Midstream Partners, L.P., the Lenders party thereto and Wells Fargo Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to Form 8-K filed October 20, 2016).
*(h)	Executive Severance Pay Plan dated July 21, 2011 (filed as Exhibit 10.2 to Form 10-Q filed August 4, 2011).
(i)	Form of 2017 Performance Based Phantom Unit Agreement for awards granted pursuant to the Magellan Midstream Partners Long-Term Incentive Plan.
(j)	Form of 2017 Executive Retention Phantom Unit Agreement for awards granted pursuant to the Magellan Midstream Partners Long-Term Incentive Plan.
*(k)	Form of Commercial Paper Dealer Agreement between Magellan Midstream Partners, L.P., as Issuer, and the Dealer party thereto (filed as Exhibit 10.1 to Form 8-K filed April 22, 2014).
*(l)	Separation and Release of Claims Agreement dated as of May 18, 2015 between Magellan Midstream Holdings GP, LLC and Michael P. Osborne (filed as Exhibit 10.1 to Form 10-Q filed August 6, 2015).
*(m)	Form of Indemnification Agreement by and among Magellan Midstream Partners, L.P., Magellan GP, LLC and the directors and officers of Magellan GP, LLC (filed as Exhibit 10.1 to Form 10-Q filed November 3, 2015).
Exhibit 12	Ratio of earnings to fixed charges.
Exhibit 14	
*(a)	Code of Ethics dated February 1, 2011 by Michael N. Mears, principal executive officer (filed as Exhibit 14(a) to Form 10-K filed February 25, 2011).
*(b)	Code of Ethics dated May 18, 2015 by Aaron L. Milford, principal financial and accounting officer (filed as Exhibit 14(b) to Form 10-K filed February 20, 2016).
Exhibit 21	Subsidiaries of Magellan Midstream Partners, L.P.
Exhibit 23	Consent of Independent Registered Public Accounting Firm.

Exhibit No.	Description
Exhibit 31	
(a)	Certification of Michael N. Mears, principal executive officer.
(b)	Certification of Aaron L. Milford, principal financial officer.
Exhibit 32	
(a)	Section 1350 Certification of Michael N. Mears, Chief Executive Officer.
(b)	Section 1350 Certification of Aaron L. Milford, Chief Financial Officer.
Exhibit 101.INS	XBRL Instance Document.
Exhibit 101.SCH	XBRL Taxonomy Extension Schema.
Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase.
Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase.
Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

* Each such exhibit has heretofore been filed with the Securities and Exchange Commission as part of the filing indicated and is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MAGELLAN MIDSTREAM PARTNERS, L.P.
(Registrant)

By: MAGELLAN GP, LLC, its general partner

By: /s/ AARON L. MILFORD

Aaron L. Milford
Senior Vice President
and Chief Financial Officer

Date: February 17, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated.

Signature	Title	Date
/s/ MICHAEL N. MEARS **Michael N. Mears**	Chairman of the Board and Principal Executive Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 17, 2017
/s/ AARON L. MILFORD **Aaron L. Milford**	Principal Financial and Accounting Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 17, 2017
/s/ WALTER R. ARNHEIM **Walter R. Arnheim**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 17, 2017
/s/ ROBERT G. CROYLE **Robert G. Croyle**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 17, 2017
/s/ LORI A GOBILLOT **Lori A Gobillot**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 17, 2017
/s/ EDWARD J. GUAY **Edward J. Guay**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 17, 2017
/s/ STACY P. METHVIN **Stacy P. Methvin**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 17, 2017
/s/ JAMES R. MONTAGUE **James R. Montague**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 17, 2017
/s/ BARRY R. PEARL **Barry R. Pearl**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 17, 2017