MAGELLAN MIDSTREAM PARTNERS LP
Form 10-K
February 17, 2017

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)
x 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
o 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 x No o
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 o No x
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 x No o
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 x No o
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. x
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 x Accelerated filer o Non-accelerated filer o Smaller reporting company o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No x

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.
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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

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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

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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.

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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.

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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.

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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

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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

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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

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(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)	