MAGELLAN MIDSTREAM PARTNERS LP
Form 10-K
February 24, 2014

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, 2013
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 (State or other jurisdiction of incorporation or organization)	73-1599053 (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 28, 2013 was $12,320,730,416.

As of February 21, 2014, there were 227,068,257 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 2014 Annual Meeting of Limited Partners are to be incorporated by reference in Part III of this Form 10-K.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
FORM 10-K
PART I
Item 1. Business

(a) General Development of Business

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

(b) Financial Information About Segments

See Part II—Item 8. Financial Statements and Supplementary Data.

(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, 2013, our asset portfolio including the assets of our joint ventures consisted of:

- our refined products segment, including our 9,500-mile refined products pipeline system with 53 terminals as well as 27 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

- our crude oil segment, comprised of approximately 1,100 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 18 million barrels, of which 12 million is used for leased storage; and

- our marine storage segment, consisting of marine terminals located along coastal waterways with an aggregate storage capacity of approximately 27 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 safest, lowest-cost 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 describes products that we transport, store and distribute through our pipelines and terminals:

- refined products, which 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, which are produced as by-products of the crude oil refining process and in connection with natural gas production. LPGs include butane and propane;

- blendstocks, which 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, which 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, which are used as feedstocks by refineries and petrochemical facilities;

- biofuels, such as ethanol and biodiesel, which are increasingly required by government mandates; and

- ammonia, which 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 9,500 miles from the Gulf Coast 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 27 refined products terminals with 5 million barrels of storage located primarily in the southeastern U.S. and connected to third-party common carrier interstate pipelines, including 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,		
	2011	2012	2013
Percent of consolidated revenue	87%	86%	81%
Percent of consolidated operating margin	77%	75%	71%
Percent of consolidated total assets	68%	57%	58%

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

Operations. Transportation, Terminalling and Ancillary Services. During 2013, 68% 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 37 of our pipeline system's 53 connected terminals. Revenue from terminalling and storage at the other 16 terminals on our refined products pipeline system is at privately negotiated rates. Some customers have made volume commitments to us in exchange for a reduced or discounted tariff rate. Under these agreements, if the customer fails to ship the committed volumes during the periods specified in the contract, they are required to pay us for the difference between the actual volumes shipped and the committed volumes.

In 2013, the products transported on our refined products pipeline system were comprised of 58% gasoline, 35% distillates and 7% aviation fuel and LPGs. The operating statistics below reflect our pipeline system's operations for the periods indicated:

	Year Ended December 31,		
	2011	2012	2013
Shipments (thousand barrels):			
Refined products:			
Gasoline	208,852	223,692	239,676
Distillates	136,003	136,709	146,493
Aviation fuel	25,245	21,557	21,117
LPGs	4,927	8,475	7,827
Total shipments	375,027	390,433	415,113

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

Our independent terminals generate revenue primarily by charging fees based on the amount of product delivered through our facilities and from ancillary services such as additive injections and ethanol blending. Our ammonia pipeline system generates revenue primarily through transportation tariffs on volumes shipped.

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 to products related to our butane blending and fractionation activities on our refined products pipeline system, and we previously took title to linefill related to a portion of the Houston-to-El Paso pipeline segment until the conversion of that pipeline segment from refined products service to crude oil service in 2012. Furthermore, under our tariffs, we are allowed to deduct from our shippers' inventory a prescribed quantity of the products our shippers transport on our pipeline 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. To the extent we can manage our volume losses below the deducted amount, our operating expenses are reduced by the value of those excess products.

Commodity-Related Activities. Product sales revenue in our refined products segment primarily results from our butane blending and transmix fractionation activities, as well as from the sale of terminal product gains at our independent terminals. 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 gasoline vapor pressure specification requirements and by the varying quality of the gasoline products delivered to us. We typically hedge the margin from this blending activity by entering into either forward physical or NYMEX gasoline futures contracts at the time we purchase the related butane. These blending activities accounted for approximately 84% of the total product margin for the refined products segment during 2013. If the differential between the cost of butane and the price of gasoline were to narrow, which generally occurs when crude oil prices decrease, the product margin we earn from these activities would be negatively impacted. We also operate two 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 $144.6 million, $136.7 million and $163.6 million for the years ended December 31, 2011, 2012 and 2013, respectively. The amount of margin we earn from these activities fluctuates with changes in petroleum prices. Product margin is not a generally accepted accounting principle ("GAAP") financial measure, but its components are determined in accordance with GAAP. Product margin, which is calculated as product sales revenue less cost of product sales, is used by management to evaluate the profitability of our commodity-related activities. The components of product margin included in operating profit, the nearest GAAP measurement, is provided in Note 16—Segment Disclosures to the consolidated financial statements included in Item 8.

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 require us to carry significant levels of inventories. We use derivative instruments to hedge against commodity price changes and manage risks associated with our various commodity purchase and sale obligations as well as for tank bottom and certain line fill inventories. 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. Our strategies are primarily intended to mitigate and manage price risks that are inherent in our butane blending and fractionation activities and tank bottom and certain line fill inventories.

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, mid-continent and Chicago-area 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 January 2014 projections provided by the Energy Information Administration, 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 any demand or supply shifts that may occur.

In 2013, approximately 68% of the products transported on our refined products pipeline system originated from 19 direct refinery connections and 32% 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
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
National Cooperative Refining Association	McPherson, KS
Northern Tier	St. Paul, MN
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	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; Greenville, 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	Borger, TX refinery, various Billings, MT area refineries
Shell	East Houston, TX	Deer Park, TX refinery
West Shore	Chicago, IL	Various Chicago, IL area refineries

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In certain markets, barge, truck or rail provide an alternative source for transporting refined products; however, pipelines are generally the lowest-cost 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 concerns regarding corrosion and product contamination, pipelines have generally not shipped ethanol, and most ethanol is transported by railroad or truck. 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. We earn revenue for these services that to date have been more than sufficient to offset any reduction in transportation revenue due to ethanol blending.

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, railroads, airlines 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 and/or term commitments in exchange for reduced tariff rates or capital expansion commitments on our part. For 2013, approximately 53% of the shipments on our pipeline system were subject to these agreements. The average remaining life of these contracts was approximately three years as of December 31, 2013, with remaining terms of up to 12 years. While many of these 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, 2013, 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, 2013 represented 42% of total revenue for our refined products segment and 60% 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 the contract period.

Our ammonia pipeline system ships product for three customers who own production facilities connected to our system. We have rolling three-year 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 companies. These sales agreements are generally short-term in nature.

CRUDE OIL

Our crude oil segment is comprised of approximately 1,100 miles of crude oil pipelines with an aggregate storage capacity of approximately 18 million barrels of storage, of which 12 million is used for leased storage, including: (i) the Longhorn crude oil 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 condensate components of our Corpus Christi, Texas terminal; (vi) the Gibson, Louisiana terminal; and (vii) the assets owned by our Osage Pipe Line Company, LLC (“Osage”), Double Eagle Pipeline LLC (“Double Eagle”) and BridgeTex Pipeline Company, LLC ("BridgeTex") joint ventures.

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

	Year Ended December 31,		
	2011	2012	2013
Percent of consolidated revenue	4%	5%	10%
Percent of consolidated operating margin	10%	12%	18%
Percent of consolidated total assets	11%	20%	26%

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 inventory at our crude oil terminal in Cushing, Oklahoma that is not sold in the normal course of business and is classified as a long-term asset on our consolidated balance sheets. In addition, we are allowed under our tariffs to deduct from our shippers' inventories a prescribed quantity of the crude oil our shippers transport on our pipeline 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. To the extent we can manage our volume losses below the deducted amount, our operating expenses are reduced by the value of those excess products.

The 450-mile Longhorn crude oil pipeline began transporting crude oil from the Permian Basin in West Texas to Houston, Texas in early 2013 when we completed the project to reverse a portion of our Houston-to-El Paso pipeline segment, which had previously transported refined products, and convert it to crude oil service. We initially began operation of the Longhorn pipeline in crude oil service at 75,000 barrels per day during mid-April 2013, increasing our actual average transportation volumes to 185,000 barrels per day by fourth quarter 2013. Shipments originate on the Longhorn pipeline in Crane or Midland, Texas via 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. We are in the process of expanding the Longhorn pipeline by 50,000 barrels per day to an

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operating capacity of 275,000 barrels per day, which we expect to achieve in mid-2014 subject to regulatory approval.

Our East Houston terminal includes approximately three million barrels of crude oil storage, with approximately one million barrels used for leased storage and two million barrels dedicated to the operation of the Longhorn pipeline. The Longhorn pipeline delivers crude oil to our East Houston terminal, as will the BridgeTex pipeline when it is completed. (See discussion of our BridgeTex joint venture under Joint Venture Activities below.) Our East Houston terminal is connected to our Houston-area crude oil distribution system and to third-party pipelines, including the Houston-to-Houma pipeline. We are building additional operational storage at this location to facilitate movements on the Longhorn and BridgeTex pipelines.

Our Houston-area crude oil distribution system consists of multiple pipeline segments that extend approximately 70 miles from our East Houston terminal through several interchanges to various points, including multiple refineries throughout Houston 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 hub in Cushing, Oklahoma and crude oil imports. In connection with construction of the BridgeTex pipeline, we are expanding the capacity of this system and developing connections to additional facilities in the area.

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 that we can lease. 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 300 miles of pipeline in Kansas and Oklahoma currently used for crude oil service. A majority 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 leased storage and a portion used in conjunction with our Double Eagle joint venture discussed below. These assets receive product primarily from barges and pipelines that connect to our terminal and are for further distribution to end users by pipeline, via waterborne vessels or our condensate off-loading truck rack.

Joint Venture Activities. We own a 50% interest in and operate the Osage pipeline, which consists of a 135-mile pipeline that transports crude oil from Cushing to two refineries in Kansas. We receive a management fee for operating Osage.

We own a 50% interest in the Double Eagle pipeline, a joint venture with Kinder Morgan Energy Partners, L.P. ("Kinder"), that transports condensate from the Eagle Ford shale formation in South Texas via a 195-mile pipeline to our terminal in Corpus Christi. An affiliate of Kinder serves as the operator of Double Eagle.

We own a 50% interest in BridgeTex, a joint venture with an affiliate of Occidental Petroleum Corporation. BridgeTex was formed to construct and operate the BridgeTex pipeline system, which will consist of a 400-mile pipeline capable of transporting 300,000 barrels per day of Permian Basin crude oil from Colorado City, Texas to our East Houston terminal, as well as combined operational crude oil storage at Colorado City and East Houston of approximately three million barrels and a 50-mile pipeline between East Houston and Texas City, Texas. We expect to spend a total of approximately $600 million, including $250 million we have spent as of December 31, 2013, in connection with our 50% ownership interest in BridgeTex. We serve as construction manager, for which we receive a construction management fee, and will serve as operator of BridgeTex upon its completion, which is expected in mid-2014.

Markets and Competition. Market conditions experienced by our crude oil pipelines vary significantly by location. Our Longhorn pipeline delivers Permian Basin production to trading and demand centers in the Houston area, and consequently depends on the level of production in the Permian Basin for its 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 at Cushing, Oklahoma. 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. Our Longhorn pipeline competes 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. The Longhorn pipeline also competes with truck and rail alternatives for Permian Basin barrels. Indirectly, the Longhorn pipeline also competes with other alternatives for delivering similar quality crude oil to the Gulf Coast, including pipelines from other producing basins such as the Eagle Ford shale or Gulf of Mexico, as well as waterborne imports. Competition is based primarily on tariff rates, proximity to both supply and demand centers, connectivity and customer relationships. Upon its completion, the BridgeTex pipeline will be subject to similar competition and market dynamics.

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 system competes with other distribution facilities in the Houston area based primarily on tariff rates and connectivity.

Our crude oil storage facilities in Cushing serve customers who value Cushing's location as an interchange point for numerous interstate pipelines 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 and/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 with other pipelines that are capable of transporting condensate from the Eagle Ford production area. Competition is based primarily on tariff rates, delivery mode 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.

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. Our customers range from independent producers, refiners and marketers to regional cooperatives, international trading companies and major integrated oil companies. Published transportation tariffs filed with the FERC or the Texas Railroad Commission primarily serve as contracts on our crude oil pipelines, and shippers nominate the volume 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 ship at higher rates than those charged to committed shippers. We must reserve 10% of the shipping capacity of our pipelines for spot shippers. We have secured long-term agreements to support our crude oil pipeline assets. Specifically with regard to our Longhorn pipeline, all of the volumes on that system, including the additional volumes that will be created from our current expansion project, are supported by long-term customer agreements. For 2013, approximately 28% of the shipments on our crude oil pipelines were subject to long-term agreements. The average remaining life of these contracts was approximately five years as of December 31, 2013. As of December 31, 2013, 100% of our crude oil storage used for leased storage was under contracts with terms in excess of one year, with an average remaining life of approximately three years. These contracts obligate the customer to pay for storage capacity reserved even if not used by the customer. Double Eagle and BridgeTex also have long-term contracts which support the capital investments in these pipeline systems.

MARINE STORAGE

We own and operate five marine storage terminals located along coastal waterways with approximately 26 million barrels of aggregate storage capacity and approximately one million additional 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 and other large 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,		
	2011	2012	2013
Percent of consolidated revenue	9%	9%	9%
Percent of consolidated operating margin	13%	13%	11%
Percent of consolidated total assets	16%	15%	13%

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 large storage capacity. Because the rates charged at these terminals are unregulated, the marketplace determines the prices we can 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 14 million barrels of usable storage capacity. This facility currently stores a mix of refined products, blendstocks and heavy oils, and we have recently added crude oil storage capabilities to this location. We receive products in this terminal via pipeline, truck, rail, barge and ship and distribute products from this facility via truck, rail, barge and pipeline. 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. We also own a 50% interest in Texas Frontera, which owns approximately one million additional barrels of storage at our Galena Park terminal. This storage is leased under an agreement with a 9-year remaining term to 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.

Our New Haven, Connecticut marine terminal is located on the Long Island Sound near the New York Harbor and has 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 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 and ethanol. We receive products at our Wilmington terminal by 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.

Markets and Competition. We believe that the continued strong demand for storage and ancillary services at our marine terminals results from our cost-effective distribution services and key transportation links, which provide us with a stable base of storage fee revenue. 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.

Several major and integrated oil companies have their own proprietary storage terminals that are or have been used in their refining operations. If these companies choose to shut down their refining operations and elect to store and distribute petroleum products through their proprietary terminals, we could experience increased competition for the services we provide. This trend is especially evident in the northeastern U.S., where our Wilmington, Delaware facility has experienced reduced utilization. In addition, other companies have facilities that offer competing storage and distribution services, and a significant amount of additional competing storage capacity has been constructed recently.

Customers and Contracts. We have long-standing relationships with refineries, suppliers and traders at our marine terminals. During 2013, approximately 90% of our storage terminal capacity was utilized with the remaining 10% not utilized primarily due to tank integrity work throughout the year. As of December 31, 2013, approximately 90% of our usable storage capacity was under contracts with remaining terms in excess of one year or that renew on an annual basis. The average remaining life of our storage contracts was approximately four years as of December 31, 2013. These contracts obligate the customer to pay for terminal capacity reserved even if not used by the customer.

GENERAL BUSINESS INFORMATION

Major Customers

No customer accounted for 10% or more of our consolidated total revenue in 2013. However, one customer accounted for 21% and 14% of our consolidated total revenue in 2011 and 2012, respectively. The majority of revenue from this customer resulted from sales of refined products that were generated in connection with our butane blending and fractionation activities and from sales associated with the management of our linefill for the Houston-to-El Paso pipeline section, all of which are or were activities conducted by our refined products segment.

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, including rates for all petroleum products, be filed with the FERC and posted publicly and that these rates be nondiscriminatory and “just and reasonable” when taking into account our cost of service. Rates of interstate pipeline companies, including approximately 40% of the shipments on our refined products pipeline system, are currently regulated by the FERC primarily through an index methodology, which for the five-year period beginning July 1, 2011, was set at the annual change in the producer price index for finished goods (“PPI-FG”) plus 2.65%. In general, we are permitted to raise our rates up to the ceiling established by the PPI-FG index plus 2.65%. Rate increases 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/or pay reparations for up to two years of over-earning. As an alternative to cost-of-service based rates, interstate pipeline companies may elect to support rate filings by obtaining authority to charge market-based rates, by settlement with respect to existing rates or through an agreement with an unaffiliated person who intends to use the related service.

Approximately 60% of our refined products pipeline system's markets are deemed competitive by the FERC, and, therefore, we are allowed to charge market-based rates in these markets.

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 crude oil pipelines, move within a single state and thus are considered to be intrastate commerce. Our 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. In most instances, state commissions have not initiated investigations of the rates or practices of these pipelines in the absence of shipper complaints.

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. FERC may also order reparations and suspend tariffs, including our authority to charge negotiated rates, for violations of the Interstate Commerce Act in connection with interstate oil pipeline transportation.

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. Since the enactment of the Energy Policy Act of 2005, we became an obligated party under the Environmental Protection Agency's ("EPA") Renewable Fuel Standard (“RFS”) 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 must either contain the mandated renewable fuel components, or credits must be purchased to cover any shortfall. We met our RVO requirements for 2013 and expect to satisfy the requirements for 2014 mainly through the purchase of credits, known as Renewable Identification Numbers. 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 remains limited. This phenomenon, better known as the “blend wall”, is expected to present compliance challenges to the RFS standards in future years unless Congress takes action to reduce the renewable fuels requirements.

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 operated and maintained in material compliance with these laws and regulations and in accordance with other generally accepted industry standards and practices.

Environmental. Estimates for remediation costs 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. Remediation costs 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 and cash flow.

Environmental Liabilities. Liabilities recognized for estimated environmental costs were $48.3 million and $38.5 million at December 31, 2012 and 2013, respectively. Environmental liabilities have been classified as current or noncurrent based on management's estimates regarding the timing of actual payments. Management estimates that expenditures associated with these environmental liabilities will be substantially paid over the next 10 years.

Environmental Receivables. Receivables from insurance carriers related to environmental matters were $7.9 million and $4.8 million at December 31, 2012 and 2013, respectively.

Environmental Insurance Policies. We have insurance policies that provide coverage for environmental matters associated with liabilities arising from sudden and accidental releases of products applicable to all of our assets. We have pollution legal liability insurance policies to cover pre-existing unknown conditions for a portion of our assets that have various terms, with most expiring between 2014 and 2017.

Stationary Engine Emission Standards. The EPA set May 2013 as the compliance date for the reduction of carbon monoxide from the exhausts of large stationary reciprocating internal combustion engines. Some of the engines on our refined products system are subject to these EPA mandates. The EPA rule, which became effective in May 2010, involves the installation of catalytic converters to the engine exhaust to achieve compliance. We have received a one-year extension to meet the stationary engine emission standards. If we are not able to modify these engines by May 2014, sections of our refined products system could experience capacity reductions or we could be assessed significant penalties until the required emission reductions are achieved. Pilot tests involving modifications to engine fuels and control systems, and application of exhaust catalytic converters have yielded favorable emission results. Based on these favorable pilot tests, through December 31, 2013, we have completed modifications to a majority of the affected engines on our refined products pipeline system and expect to have the modifications to the remaining engines completed before the end of March 2014. Formal engine testing, subject to witnessing by the EPA, will be conducted in 2014 following our completion of this project.

Department of Homeland Security Appropriation Act of 2007. This act requires the Department of Homeland Security (“DHS”) to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present “high levels of security risk.” The DHS has issued rules that establish chemicals of interest and their respective threshold quantities that trigger compliance with these standards. The owners of facilities covered by these DHS rules that are determined by the DHS to pose a higher level of security risk are required to prepare and submit security vulnerability assessments and site security plans as well as comply with other regulatory requirements, including those regarding inspections, audits, record-keeping and protection of chemical-terrorism vulnerability information.

Although the program was created in 2007, the DHS has yet to determine whether gasoline storage facilities are to be included in the regulatory requirements. Regardless of the outcome, management believes our costs to comply with the rule will not be material.

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 and Clean Water Act ("CWA"). The CWA subjects 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 navigable 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 navigable 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 navigable waters. This law and comparable state laws require that permits be obtained to discharge pollutants into state and federal waters and impose substantial potential liability for non-compliance. Where required, we hold discharge permits that were issued under the CWA or a state-delegated program. While we have occasionally exceeded permit discharges at some of our terminals, we do not expect our non-compliance with existing permits to have a material adverse effect on our results of operations, financial position or cash flows.

Greenhouse Gas Emissions. In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the

Clean Air Act ("CAA"). Among several such regulations, in May 2010, the EPA finalized its "tailoring rule," determining which stationary sources of greenhouse gases are required to obtain permits and implement best available control technology standards on account of their greenhouse gas emission levels. The EPA's endangerment finding and greenhouse gas rules were upheld by the U.S. Court of Appeals for the D.C. Circuit in June 2012, and a petition for review of the case by the entire D.C. Circuit was denied in December 2012.

Further, Congress has considered various proposals to reduce greenhouse gas emissions that may impose a carbon emissions tax, a cap-and-trade program or other programs aimed at carbon reduction. Such legislation would have established an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases including carbon dioxide and methane that may contribute to the warming of the earth's atmosphere and other climatic changes. The current administration supports legislation to reduce greenhouse gas emissions through an emission allowance system. As allowances under such a system would be expected to significantly escalate in cost over time, the net effect of any potential cap-and-trade legislation would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products and natural gas. In addition, at least one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap-and-trade programs. Our compliance with any future legislation or regulation of greenhouse gases, if it occurs, may result in materially increased compliance and operating costs. It is not possible at this time to predict with any accuracy the structure or outcome of any future legislative or regulatory efforts to address such emissions or the eventual costs to us of compliance.

Maintenance. Our pipeline systems are subject to regulation by the U.S. Department of Transportation 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. HLPSA covers crude oil, refined products and anhydrous ammonia and requires any entity that owns or operates pipeline facilities to comply with such regulations, permit access to and copying of records and make certain reports and provide information as required by the Department of Transportation. Our assets are also subject to various federal security regulations, and we believe we are in substantial compliance with all applicable regulations.

The Department of Transportation requires operators of hazardous liquid interstate pipelines to develop and follow an integrity management program that provides for assessment of the integrity of all pipeline segments that could affect designated “high consequence areas,” including high population areas, drinking water, commercially navigable waterways and ecologically sensitive resource areas. Segments of our pipeline systems have the potential to impact high consequence areas. In addition to regulations applicable to all of our pipelines, as part of the Longhorn development projects, 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 Department of Transportation through the Pipeline and Hazardous Materials Safety Administration.

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

Safety. Our assets are subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) and comparable state statutes, which, among other things, require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to employees, 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. We believe we are in material compliance with OSHA and comparable state safety regulations.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 reauthorized funding for federal pipeline safety programs through 2015, 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. The Pipeline Hazardous Materials Safety Administration of the Department of Transportation has also published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines. Compliance with such legislative and regulatory changes could have a material effect on our results of operations, financial position or cash flows.

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property, and in some instances, these rights-of-way have limited terms that may require periodic renegotiation or, if such negotiations are unsuccessful, may require us to seek to exercise the power of eminent domain. 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 for the transfer of the assets necessary for us 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, 2013, we had 1,459 employees. At December 31, 2013, the labor force of 842 employees assigned to our refined products segment was concentrated in the central U.S. Approximately 26% of these employees were represented by the United Steel Workers and covered by a collective bargaining agreement that expires January 31, 2015. At December 31, 2013, the labor force of 51 employees assigned to our crude oil segment was 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, 2013 was primarily located in the Gulf and East Coast regions of the U.S. Approximately 16% of these employees were represented by the International Union of Operating Engineers and covered by a collective bargaining agreement that expires October 31, 2016.

(d) Financial Information About Geographical Areas

We have no international activities. For all periods included in this report, all 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 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 certain 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 and results of operations. However, these risks are not the only risks that we face. Our business could also be impacted by additional risks and uncertainties not currently known or that we currently deem 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. In that case, the market price of our limited partner units could decline.

Risks Related to Our Business

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 following establishment of cash reserves.

The amount of cash we can distribute on our limited partner units 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 fluctuates from quarter to quarter and may change over time. Significant and sustained reductions in the cash generated by our operations could reduce our ability to pay quarterly distributions in future periods.

Our financial results depend on the demand for the petroleum products that we transport, store and distribute, among other factors, and unfavorable economic conditions 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, including the challenges that have affected economic conditions in the U.S. over the last several years. If economic and market conditions remain uncertain or adverse conditions persist for an extended period, we could experience material impacts on our business, financial condition and 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 in the market prices of petroleum products, which may reduce 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;
- 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, in August 2012 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. The proposed standards are intended to reduce demand for petroleum products, and if implemented these and any similar standards 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 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 lease renewals or renewals at substantially lower rates at our storage terminals or in leased storage along our pipelines could cause our leased storage revenue to decline, which would adversely impact our results of operations and the amount of cash we generate.

Most of the revenue we earn from leased storage at our marine and crude oil terminals and along our pipeline system is provided for in contracts negotiated with our leased 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 leased 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 leased 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 leased 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 leased 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 leased 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 and cash flows.

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 and/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 lease storage capacity or be forced to reduce the rates we charge for leased storage capacity, either of which would materially reduce the amount of cash we generate.

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. For the five-year period beginning July 1, 2011, the indexing method provides for annual changes in rates by a percentage equal to the change in the PPI-FG plus 2.65%. This methodology could result in changes in our revenue that does 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 2.65% used by the current FERC methodology. Further, in periods of general price deflation, the PPI-FG index could fall, in which case we could be required to reduce our index-based rates, 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. In addition, 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 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 could have 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 have increased significantly, and could escalate further 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 adversely 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 those 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/or 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 require 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 and/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.

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

We depend on crude oil production and connections with gathering systems, refineries and petroleum pipelines owned and operated by third parties to supply our assets. Changes in the quality or quantity of crude oil produced in the field, outages at these refineries or reduced or interrupted throughput on these gathering systems or pipelines due to weather-related or other natural causes, testing, line repair, damage, reduced operating pressures or other causes could result in our being unable to deliver products to our customers from our terminals or receive products for storage or reduce shipments on our pipelines and 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 sometimes global supply and demand dynamics that are difficult to predict. A period of sustained weak demand or increased cost of supply could make refining uneconomic for some refineries, including those located along our refined products and crude oil pipelines. The closure of a refinery that delivers product to or receives crude from our refined products or crude oil pipelines could reduce the volumes we transport and the amount of cash we generate. Further, the closure of these or other refineries could result in companies electing to store and distribute refined petroleum products through their proprietary terminals, which could result in a reduction of our storage volumes.

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. 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, 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 new pipelines to deliver crude oil from the Permian Basin in West Texas to markets along the U.S. Gulf Coast. Similar investments have been made and additional investments may be made in the future by our competitors or by new entrants to the markets we serve. The success of these and similar projects largely relies on the realization of anticipated market demand, and these projects typically require significant development periods, during which time demand for such infrastructure may change, or additional investments by competitors may be made. If infrastructure investments by us or others in the markets we serve result in capacity that exceeds the demand in those markets, our facilities could be underutilized, we could be forced to reduce the rates we charge for our services, the value of our assets could decrease and the returns on our investments in those markets could fail to meet our expectations.

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

Mergers among our existing customers and our competitors could provide strong economic incentives for the combined entities to utilize their existing systems instead of ours in those markets where our systems compete. As a result, we could lose some or all of the volumes and associated revenue from these customers, and we could experience difficulty in replacing those lost volumes and revenue. As most 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.

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 future targets of terrorist organizations. The threat of terrorist attacks has subjected our operations to increased risks. Any future 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 future 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.

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 operation of our pipelines and terminals. We also maintain product inventory related to these activities. 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 non-cash 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 may 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.

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 under Accounting Standards Codification 815-30, 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. To the extent these hedges are entered into on a public exchange, we may be required to post margin, which could result in material cash obligations. These contracts may be for the purchase or sale of product in markets different from those in which we are attempting to hedge our exposure, resulting in hedges that do not eliminate all price risks. If we incur material amounts of ineffectiveness in our hedging strategies, our quarterly or annual results of operations could be negatively impacted, which could have a negative impact on our unit price. Further, our requirement to post material amounts of margin on the hedge contracts we have entered into could negatively impact our ability to pay distributions to our unitholders.

Failure to generate 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, 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.

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

We have begun 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, if at all, until sometime after the projects are completed. As a result, our leverage 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 and/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 and/or cost overruns. 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 and/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. Any cost overruns or unanticipated delays in the completion or commercial development of our expansion projects could reduce the anticipated returns on these projects, which in turn could materially increase our leverage and reduce our liquidity and our ability to pay cash distributions.

Potential future acquisitions and expansions may affect our business by substantially increasing the level of our indebtedness and liabilities, incurring 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 that we believe complement our existing 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 will 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 could dilute our existing limited partner unitholders and 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 and/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.

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.

We participate in several joint ventures, in each of which we share control of the joint venture 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. In addition, many activities of the joint ventures may only be authorized by agreement between us and the other owners of those joint ventures. In the case of Double Eagle Pipeline LLC, our joint venture co-owner serves as operator, and consequently we rely on our joint venture co-owner for many of the management functions of that joint venture. Without the cooperation of the other owners of those joint ventures, we are unable 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. If we are unable to agree with our joint venture co-owner on a significant matter, it 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.

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.

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.

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 tariff rates for interstate movements and state regulatory authorities regulate the tariff rates for intrastate movements on our refined products and crude oil pipelines. 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 reparations to complaining shippers and/or 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 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 allows 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. In December 2010, the FERC established a new price index level equal to the annual change in the PPI-FG expressed as a percentage, plus 2.65% for the five-year period beginning July 1, 2011. If the PPI-FG falls and our rates are at the ceiling level, we would be required to reduce our rates that are subject to the FERC's price indexing methodology.

We establish rates in approximately 60% of the markets for our refined products pipeline using the FERC's market-based ratemaking regulations. These regulations allow us to establish rates based on conditions in individual markets without regard to the index or our cost-of-service. 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.

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 Clean Air Act ("CAA"), the RCRA, the Oil Pollution Act and Clean Water Act ("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/or 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 and 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 under CERCLA, RCRA, the Water Pollution Control Act or analogous state laws for the remediation of contaminated areas. 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/or may not provide sufficient coverage in the event an environmental claim is made against us.

Our assets have been used for many years to transport, store or distribute petroleum products. 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. 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 reauthorized funding for federal pipeline safety programs through 2015, 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. The Pipeline Hazardous Materials Safety Administration of the U.S. Department of Transportation has also published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines. Compliance with such legislative and regulatory changes could 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 federal and state authorities and that could be subjected to increased regulatory costs, delays or liabilities. 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.

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. Among several such regulations, in May 2010, the EPA finalized its "tailoring rule," determining which stationary sources of greenhouse gases are required to obtain permits and implement best available control technology standards on account of their greenhouse gas emission levels. The EPA's endangerment finding and greenhouse gas rules were upheld by the U.S. Court of Appeals for the D.C. Circuit in June 2012, and a petition for review of the case by the entire D.C. Circuit was denied in December 2012. Further, Congress has considered various proposals to reduce greenhouse gas emissions that may impose a carbon emissions tax, a cap-and-trade program or other programs aimed at carbon reduction. Such legislation would have established an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases including carbon dioxide and methane that may contribute to the warming of the earth's atmosphere and other climatic changes. The current administration supports legislation to reduce greenhouse gas emissions through an emission allowance system. As allowances under such a system would be expected to significantly escalate in cost over time, the net effect of any potential cap-and-trade legislation would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products and natural gas. In addition, at least one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap-and-trade programs. Our compliance with any future legislation or regulation of greenhouse gases, if it occurs, may result in materially increased compliance and operating costs. It is not possible at this time to predict with any accuracy the structure or outcome of any future legislative or regulatory efforts to address such emissions or the eventual costs to us of compliance.

The effect on our operations of CAA regulations, legislative efforts or related implementation rules that regulate or restrict emissions of greenhouse gases in areas that we conduct business could adversely affect the 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.

In addition, some scientists have concluded that 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, droughts, floods and other climate 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 a 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 have the option to purchase renewable energy credits, called Renewable Identification Numbers ("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 and or decreases in the availability of RINs could have an adverse impact on our results of operations, cash flows and cash distributions.

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

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

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

We are exposed to counterparty risk. Nonpayment and nonperformance by our customers, vendors, lenders or derivative counterparties could materially reduce our revenue, impair our liquidity, increase our expenses 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 upon which we rely to realize the expected return on those expenditures, and nonperformance by our customers on those commitments could result in substantial losses to us. Similarly, nonperformance by vendors who have committed to provide products or services to us could result in higher costs, reduce our revenue or otherwise interfere with the conduct of our business. 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 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 and 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 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.

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/or reduce our cash flows and ability to pay distributions.

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 $550 million to complete our current slate of organic growth projects during 2014. 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 mature in 2014, and another $250 million mature in 2016, and we anticipate raising new capital to refinance these obligations on or prior to their maturity. 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 and/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, 2013, the face value of our outstanding fixed-rate debt was $2.7 billion. We expect to make floating-rate borrowings under our revolving credit facility as needed to partially finance future expansion capital spending. 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.

Cyber attacks that circumvent our security measures and other breaches of our information security measures could disrupt our operations and result in increased costs.

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, including our proprietary business information and information about our customers, suppliers and other counterparties, and personally identifiable information of our employees, on our networks. 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. 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, could disrupt our operations, and could damage our reputation, 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.

The effect of recent changes to U.S. healthcare laws may increase our healthcare costs and negatively impact our financial results.

We offer eligible employees the opportunity to enroll in healthcare coverage that we subsidize. The comprehensive U.S. health care reform law enacted in 2010, the Affordable Care Act, and subsequent IRS regulations may increase our labor costs significantly, especially the employer mandate, which requires us to offer health care coverage to 70% (in 2015) and 95% (beginning in 2016) of our employees and employer penalties that are scheduled to become effective in 2015. Implementing the requirements of the Affordable Care Act will impose additional administrative costs on us. The costs and other effects of these new healthcare requirements cannot be determined with certainty; however, they could have a significant adverse effect on our operating results.

We have contracted various functions to third-party service providers, which transfers the execution of these services to the third-party providers and decreases our control over the performance of these functions. Disruptions or delays of our third-party service providers could result in delays in project completions, increased costs or adversely affect service levels.

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 operations, or instances of a contractor’s non-compliance with applicable laws and regulations which could materially adversely affect our business, financial condition, operating results and cash flows.

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

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

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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.

If you are not a citizenship eligible holder, your limited partner units 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 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.

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, 2013, we had approximately $3,916 million of net property, plant and equipment, $361 million of investments in non-controlled entities and $53 million of goodwill. U.S. generally accepted accounting principles requires us to 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.

Tax Risks to Limited Partner Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service ("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. 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. For example, from time to time members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. 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 widespread state budget deficits and for other reasons, several states are evaluating 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.

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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.

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 day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could 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 units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. The Department of the Treasury and the IRS have issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Although existing publicly traded partnerships are entitled to rely on these proposed Treasury Regulations, they are not binding on the IRS and are subject to change until final Treasury Regulations are issued. Further, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge this method or new Treasury Regulations were issued, we may 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 that may result in a shift of income, gain, loss and deduction between our partners. The IRS may challenge this treatment, which could adversely affect the value of our limited partner units.

When we issue additional limited partner units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our partners. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between our partners, which may be unfavorable to certain unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their IRS Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Internal Revenue Code Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our partners.

A successful IRS challenge to these methods or allocations could adversely affect the amount 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 24 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.

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

Glenn A. Henke, et al. v. Magellan Pipeline Company, L.P., et al.

In February 2010, a class action lawsuit was filed against us, ARCO Midcon L.L.C. and WilTel Communications, L.L.C. ("WilTel"). The complaint alleges that the property owned by plaintiffs and those similarly situated has been damaged by the existence of hazardous chemicals migrating from a pipeline easement onto the plaintiffs' property and seeks recovery for such damages. We acquired the pipeline from ARCO Pipeline ("APL") in 1994 as part of a larger transaction and subsequently transferred the property to WilTel. We are required to indemnify and defend WilTel pursuant to the transfer agreement. Prior to our acquisition of the pipeline property from APL, the pipeline was purged of product. Neither we nor WilTel ever transported hazardous materials through the pipeline. A hearing on the plaintiffs' Motion for Class Certification was held in the U.S. District Court for the Eastern District of Missouri in December 2012. The court has not yet rendered a decision on the issue of class certification. While the results cannot be predicted with certainty, we believe that the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

2011 EPA Clean Water Act Information Request for Pipeline Release in Texas

In July 2011, we received an information request from the EPA pursuant to Section 308 of the Clean Water Act regarding a pipeline release in February 2011 in Texas. We have accrued $0.1 million for potential monetary sanctions related to this matter. While the results cannot be predicted with certainty, we believe that the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

2012 Notice of Probable Violation from PHMSA for Oklahoma and Texas

In March 2012, we received a Notice of Probable Violation from the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration ("PHMSA") for alleged violations related to the operation and maintenance of certain pipelines in Oklahoma and Texas. We have accrued approximately $0.1 million for potential monetary sanctions related to this matter. While the results cannot be predicted with certainty, we believe that the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

2012 EPA Clean Water Act Information Request for Pipeline Release in Nebraska

In April 2012, we received an information request from the EPA pursuant to Section 308 of the Clean Water Act, regarding a pipeline release in December 2011 in Nebraska. We have accrued $0.6 million for potential monetary sanctions related to this matter. While the results cannot be predicted with certainty, we believe that the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

US 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. 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. Currently, there is an ongoing removal action designed to stabilize the site, remove the immediate threat posed at the site and set the stage for a later more comprehensive action, known as the assessment phase. We have accrued and 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.

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 21, 2014, we had 227,068,257 limited partner units outstanding that were owned by approximately 134,000 record holders and beneficial owners (held in street name).

The year-end closing sales price of our limited partner units was $43.19 on December 31, 2012 and $63.27 on December 31, 2013. The high and low trading prices for our limited partner units and distribution paid per unit by quarter for 2012 and 2013 were as follows:

	2012			2013		
Quarter	High	Low	Distribution*	High	Low	Distribution*
1st	$36.87	$32.17	$0.42000	$53.91	$44.00	$0.50750
2nd	$36.46	$33.31	$0.47125	$56.29	$48.90	$0.53250
3rd	$44.25	$35.08	$0.48500	$57.18	$51.93	$0.55750
4th	$45.58	$39.06	$0.50000	$63.86	$55.30	$0.58500

* 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 $0.585 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 50 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, 2008 and that all distributions or dividends were reinvested on a quarterly basis.

	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013
Magellan Midstream Partners, L.P.	$100	$155	$215	$276	$362	$551
Alerian MLP Index	$100	$176	$240	$273	$286	$365
S&P 500	$100	$126	$145	$148	$172	$228

The information provided in this section is being furnished to, and not filed with, the Securities and Exchange Commission ("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 audited consolidated financial statements and related notes. 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 and 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 and 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 recognized in our accompanying consolidated financial statements.

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 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 pay. 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 in the accompanying consolidated financial statements 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,				
	2009	2010	2011	2012	2013
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenue	$678,945	$793,599	$893,369	$970,744	$1,138,328
Product sales revenue	334,465	763,090	854,528	799,382	744,669
Affiliate management fee revenue	761	758	770	1,948	14,609
Total revenue	1,014,171	1,557,447	1,748,667	1,772,074	1,897,606
Operating expenses	257,635	282,212	306,415	328,454	346,070
Cost of product sales	280,291	668,585	706,270	657,108	578,029
Earnings of non-controlled entities	(3,431)	(5,732)	(6,763)	(2,961)	(6,275)
Operating margin	479,676	612,382	742,745	789,473	979,782
Depreciation and amortization expense	97,216	108,668	121,179	128,012	142,230
G&A expense	84,049	95,316	98,669	109,403	132,496
Operating profit	298,411	408,398	522,897	552,058	705,056
Interest expense, net	69,187	93,296	105,634	111,679	115,782
Debt placement fee amortization	1,112	1,401	1,831	2,087	2,424
Other (income) expense, net	(24)	750	—	—	—
Income before provision for income taxes	228,136	312,951	415,432	438,292	586,850
Provision for income taxes	1,661	1,371	1,866	2,622	4,613
Net income	$226,475	$311,580	$413,566	$435,670	$582,237
Net income allocation:[(a)]					
Limited partner interests	$126,746	$311,977	$413,629	$435,670	$582,237
Non-controlling owners' interest	99,729	(397)	(63)	—	—
Net income	$226,475	$311,580	$413,566	$435,670	$582,237
Basic net income per limited partner unit	$1.11	$1.42	$1.83	$1.92	$2.57
Diluted net income per limited partner unit	$1.11	$1.42	$1.83	$1.92	$2.56
Balance Sheet Data:					
Working capital (deficit)[(b)]	$94,571	$109,536	$301,135	$307,658	$(241,543)
Total assets	$3,163,148	$3,717,900	$4,045,001	$4,420,067	$4,820,812
Long-term debt (excluding current portion)	$1,680,004	$1,906,148	$2,151,775	$2,393,408	$2,435,316
Owners’ equity	$1,196,354	$1,469,571	$1,463,403	$1,515,702	$1,647,442
Cash Distribution Data:					
Cash distributions declared per MMP unit[(c)]	$1.42	$1.48	$1.59	$1.88	$2.18
Cash distributions paid per MMP unit[(c)]	$1.42	$1.45	$1.56	$1.78	$2.10

	Year Ended December 31,				
	2009	2010	2011	2012	2013
	(in thousands, except operating statistics)				
Other Data:					
Operating margin:					
Refined products	$388,083	$491,290	$574,030	$592,828	$693,985
Crude oil	8,492	28,517	74,225	91,367	176,420
Marine storage	79,262	89,566	91,571	102,323	106,198
Allocated partnership depreciation costs(d)	3,839	3,009	2,919	2,955	3,179
Operating margin	$479,676	$612,382	$742,745	$789,473	$979,782
Adjusted EBITDA and distributable cash flow:					
Net income	$226,475	$311,580	$413,566	$435,670	$582,237
Interest expense, net	69,187	93,296	105,634	111,679	115,782
Depreciation and amortization expense(e)	98,328	110,069	123,010	130,099	144,654
Equity-based incentive compensation expense(f)	6,123	15,499	10,243	8,038	11,823
Asset retirements and impairments	5,529	1,062	8,599	12,622	7,835
Commodity-related adjustments(g)	24,262	7,751	(22,370)	12,894	(339)
Other(h)	5,685	(1,582)	(2,504)	4,850	(409)
Adjusted EBITDA	435,589	537,675	636,178	715,852	861,583
Interest expense, net	(69,187)	(93,296)	(105,634)	(111,679)	(115,782)
Maintenance capital (net of reimbursements)	(37,999)	(44,620)	(70,002)	(64,396)	(76,081)
Distributable cash flow	$328,403	$399,759	$460,542	$539,777	$669,720
Operating Statistics:					
Refined products:(i)					
Transportation revenue per barrel shipped	$1.205	$1.197	$1.175	$1.230	$1.313
Volume shipped (million barrels):					
Gasoline	169.9	194.3	208.9	223.7	239.7
Distillates	100.2	122.9	136.0	136.7	146.5
Aviation fuel	19.9	22.6	25.3	21.5	21.1
Liquefied petroleum gases	5.7	5.0	4.9	8.5	7.8
Total volume shipped	295.7	344.8	375.1	390.4	415.1
Crude oil:(i)					
Transportation revenue per barrel shipped	$—	$0.283	$0.275	$0.305	$0.880
Volume shipped (million barrels)	—	14.7	43.2	72.0	113.2
Crude oil terminal average utilization (million barrels per month)	1.2	3.4	9.3	12.6	12.3
Marine storage:					
Marine terminal average utilization (million barrels per month)	23.4	24.0	24.7	23.8	23.0

(a) In September 2009, we simplified our capital structure wherein our general partner became our wholly-owned subsidiary, our requirement to pay incentive distribution rights was eliminated and we acquired all of the non-controlling owners' interests that existed at that time. Following the simplification, all of our net income was allocated to our limited partners until the formation of Magellan Crude Oil, LLC ("MCO") in 2010, which was partially owned by a private investment group. In February 2011, we acquired all of the non-controlling owners' interest in MCO.

(b) Working capital deficit at December 31, 2013 included the current portion of long-term debt of approximately $250 million consisting of our 6.45% notes due 2014. We intend to refinance these notes with long-term debt prior to their maturity date in June 2014.

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(c) Cash distributions declared represent distributions declared associated with 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) Includes debt placement fee amortization.

(f) Excludes the tax withholdings on settlement of these 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) Other primarily includes adjustments for earnings of non-controlled entities and distributions. In 2010 and 2011, other included non-controlling owners' interests losses included in net income, and in 2009, other also included expense credited to a former affiliate.

(i) We acquired certain crude oil and refined products pipelines in South Texas during September 2010. Other than our equity interest in Osage Pipe Line Company, LLC (which is excluded from our operating statistics), we had no crude oil pipeline operations prior to that date. Until the completion of our Longhorn crude oil pipeline reversal project 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.

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, including our 9,500-mile refined products pipeline system with 53 terminals as well as 27 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

- our crude oil segment, comprised of approximately 1,100 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 18 million barrels, of which 12 million is used for leased storage; and

- our marine storage segment, consisting of marine terminals located along coastal waterways with an aggregate storage capacity of approximately 27 million barrels.

The following discussion provides an analysis of the results for each of our operating segments, an overview of our liquidity and capital resources and other items related to our partnership. 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, 2013.

Recent Developments

BridgeTex Pipeline Company, LLC. In November 2012, we formed BridgeTex Pipeline Company, LLC (“BridgeTex”), a joint venture with affiliates of Occidental Petroleum Corporation. BridgeTex was formed to construct and operate the BridgeTex pipeline, a 400-mile pipeline capable of transporting 300,000 barrels per day of Permian Basin crude oil from Colorado City, Texas for delivery to our East Houston, Texas terminal; a 50-mile pipeline between East Houston and Texas City, Texas; and approximately 2.6 million barrels of storage. We expect to spend a total of approximately $600 million, including $250 million we have spent as of December 31, 2013, in connection with our 50% ownership interest in BridgeTex. We are serving as construction manager and will serve as operator of BridgeTex upon its completion, which is expected in mid-2014.

Executive Officer Changes. Our Senior Vice President and Chief Financial Officer, John D. Chandler, has announced his resignation from such positions effective March 31, 2014. Michael P. Osborne, whom we employed in November 2013 as Senior Vice President, Finance and Accounting, will assume Mr. Chandler's positions effective April 1, 2014. Mr. Osborne had 23 years of experience with Ernst & Young LLP and served as an audit partner with that firm for 11 years.

Longhorn Pipeline. In mid-April 2013, we began deliveries of crude oil from our Longhorn pipeline. During the fourth quarter of 2013, Longhorn's crude oil deliveries averaged approximately 185,000 barrels per day. The pipeline has been capable of operating at its full 225,000 barrel-per-day capacity since mid-October. We plan to expand the capacity of the Longhorn pipeline by 50,000 barrels per day to 275,000 barrels per day, all fully committed by long-term contracts. Subject to regulatory approval, we expect to reach the 275,000 barrel-per-day operating capacity by mid-2014. We estimate this expansion project will cost approximately $55 million.

Pipeline Acquisition. In February 2013, we announced an agreement to acquire approximately 800 miles of refined petroleum products pipeline from Plains All American Pipeline, L.P. ("Plains"). On July 1, 2013, we closed on a portion of this transaction which included a 250-mile pipeline that transports refined petroleum products from El Paso, Texas north to Albuquerque, New Mexico and transports products south to the U.S.-Mexico border for delivery within Mexico via a third-party pipeline. In November 2013, we acquired the remaining assets, including approximately 550 miles of common carrier pipeline that distributes refined petroleum products in Colorado, South

Dakota and Wyoming. The system also includes four terminals with nearly 1.7 million barrels of storage. We funded this $192.0 million acquisition with cash on hand and proceeds from our recent debt offering (see Liquidity and Capital Resources–Liquidity, below for information regarding our recent debt offering). This pipeline system is a strategic fit with our existing assets and customer relationships and extends the reach of our pipeline system to allow us to serve new geographic markets. The operating results of both portions of this acquisition have been included in our refined products segment since the acquisition dates.

Cash Distribution. In January 2014, the board of directors of our general partner declared a quarterly cash distribution of $0.5850 per unit for the period of October 1, 2013 through December 31, 2013. This quarterly cash distribution was paid on February 14, 2014 to unitholders of record on February 7, 2014. The total distribution paid on 227.1 million limited partner units outstanding was $132.8 million.

Overview

Our pipelines and terminals generate the majority of our operating margin from the transportation and storage services we provide to our customers. The revenue generated from these activities is significantly influenced by demand for refined products and crude oil. In addition, we generate operating margin from commodity-related activities. Operating expenses are principally fixed costs related to routine maintenance and system integrity as well as field and support personnel. Other costs, including power, fluctuate with volumes transported on our pipelines and stored in our terminals.

Refined Products. Our common carrier pipeline system is comprised of 9,500 miles of pipeline and 53 terminals that provide transportation, storage and distribution services for refined products in a 15-state area across the central United States. Through direct refinery connections and interconnections with other interstate pipelines, our refined products pipeline can access approximately 48% of the U.S. refining capacity. In 2013, the refined products segment generated 68% of its revenue, excluding the sale of refined products, primarily through transportation tariffs for refined products shipped. These tariffs vary depending upon where the product originates, where ultimate delivery occurs and any applicable discounts. All interstate transportation rates and discounts are in published tariffs filed with the Federal Energy Regulatory Commission (“FERC”). The pipeline also earns revenue from non-tariff based activities, including leasing pipeline and storage tank capacity to shippers and by providing data services and product services such as ethanol and biodiesel unloading and loading, additive injection, terminalling, custom blending and laboratory testing. Substantially all of the shipments on our refined products pipeline are for third parties, and we do not take title to these products. We do take title to products related to our butane blending and fractionation activities and in connection with certain transactions involving the operation of our refined products pipeline and terminals.

Our blending activities involve purchasing liquefied petroleum gases and blending them into gasoline, which creates additional gasoline available for us to sell. Our fractionation activities include two fractionators along our pipeline system that separate transmix, an unusable mixture of various petroleum products, into gasoline and diesel fuel. We generate transmix from the commingling of products between different product batches during the transportation process on our refined product pipelines. We also purchase transmix from third parties.

Our independent terminals consist of 27 refined products terminals that are part of a distribution network located principally throughout the southeastern U.S. that are connected to large, third-party interstate pipelines. We earn revenue at our independent terminals primarily from fees we charge based on the volumes of refined products distributed from these locations.

Our ammonia pipeline consists of 1,100 miles of pipeline that transports and distributes anhydrous ammonia from production facilities in Texas and Oklahoma to various distribution points in the Midwest for use as an agricultural fertilizer. We generate revenue principally from volume-based fees for the transportation of ammonia on our pipeline system.

Crude Oil. Our crude oil segment includes 1,100 miles of pipeline and 12 million barrels of storage used for leased storage. A brief description of our crude oil operations is as follows:

Our Longhorn crude oil pipeline consists of approximately 450 miles of pipeline which originates in Crane, Texas for deliveries to Houston-area refineries and pipelines. The Longhorn pipeline began crude oil service operations in early 2013;

Our Houston-area crude oil distribution system originates at our East Houston, Texas terminal and other points in the Houston area for delivery to nearby refineries and other pipeline systems;

Our terminal in Cushing, Oklahoma, one of the largest crude oil trading hubs in the U.S., consists of approximately 10 million barrels of crude oil storage used for leased storage. This terminal principally serves refiners, marketers and traders. We earn revenue primarily from leasing tanks as well as from throughput fees;

Our terminal at East Houston, Texas includes approximately one million barrels of crude oil storage used for leased storage and our terminal at Corpus Christi, Texas includes approximately one million barrels of condensate storage used for leased storage; and

We own approximately 300 miles of pipeline in Kansas and Oklahoma currently used for crude oil service. A majority 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 crude oil segment also includes ownership interests in the following joint ventures:

- a 50% interest in Osage Pipe Line Company LLC ("Osage"), which owns a 135-mile pipeline that transports crude oil from Cushing, Oklahoma to refineries in El Dorado, Kansas;

- a 50% interest in Double Eagle Pipeline LLC ("Double Eagle"), which transports condensate from the Eagle Ford shale formation in South Texas via a 195-mile pipeline to our terminal in Corpus Christi. Double Eagle is operated by an affiliate of the other member of Double Eagle; and

- a 50% interest in BridgeTex, which is constructing 450 miles of pipeline and related infrastructure to transport crude oil from Colorado City, Texas for delivery to the Houston-area refineries. This pipeline is expected to begin service in mid-2014.

Marine Storage. Our marine storage segment consists of storage terminals, which store and distribute refined products. Our storage terminals are comprised of five facilities that have marine access in New Haven, Connecticut, Wilmington, Delaware, Marrero, Louisiana, and Corpus Christi and Galena Park, Texas that are located near major refining hubs along the U.S. Gulf and East Coasts. Our marine storage terminals have an aggregate storage capacity of approximately 26 million barrels of wholly-owned storage. Because the rates charged at these terminals are unregulated, the marketplace determines the prices we can charge for our services. We earn revenue through storage and ancillary fees, including product heating, blending, mixing and additive injection for refiners and other large end users of refined products. Additionally, we have a 50% interest in Texas Frontera, LLC ("Texas Frontera), a refined products storage company that owns approximately one million barrels of storage located at our terminal in Galena Park, Texas.

Growth Projects

We remain focused on growth and have significantly increased our operations over the past several years through organic growth projects and acquisitions that expand or upgrade our existing facilities. Our current expansion projects are driven by demand for crude oil and condensate storage and transportation services, which has provided the opportunity for us to further expand our Longhorn pipeline, construct the BridgeTex pipeline and add crude oil infrastructure to our Galena Park marine terminal.

During 2012 and 2013, respectively, we spent $364.7 million and $772.7 million combined on expansion capital, acquisitions and investments in non-controlled entities. Further, we currently expect to spend approximately $550.0 million in 2014 on projects now underway. These expansion capital estimates exclude potential acquisitions or spending on more than $500.0 million of other potential growth projects in earlier stages of development.

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 product 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, 2012 Compared to Year Ended December 31, 2013

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2012	2013	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenue:				
Refined products	$723.8	$801.1	$77.3	11%
Crude oil	92.3	178.4	86.1	93%
Marine storage	154.6	158.8	4.2	3%
Total transportation and terminals revenue	970.7	1,138.3	167.6	17%
Affiliate management fee revenue	2.0	14.6	12.6	630%
Operating expenses:				
Refined products	267.7	270.7	(3.0)	(1)%
Crude oil	5.2	19.1	(13.9)	(267)%
Marine storage	58.5	59.4	(0.9)	(2)%
Intersegment eliminations	(2.9)	(3.1)	0.2	7%
Total operating expenses	328.5	346.1	(17.6)	(5)%
Product margin:				
Product sales	799.4	744.7	(54.7)	(7)%
Cost of product sales	657.1	578.0	79.1	12%
Product margin [(a)]	142.3	166.7	24.4	17%
Earnings of non-controlled entities	3.0	6.3	3.3	110%
Operating margin	789.5	979.8	190.3	24%
Depreciation and amortization expense	128.0	142.2	(14.2)	(11)%
G&A expense	109.4	132.6	(23.2)	(21)%
Operating profit	552.1	705.0	152.9	28%
Interest expense (net of interest income and interest capitalized)	111.7	115.8	(4.1)	(4)%
Debt placement fee amortization	2.1	2.4	(0.3)	(14)%
Income before provision for income taxes	438.3	586.8	148.5	34%
Provision for income taxes	2.6	4.6	(2.0)	(77)%
Net income	$435.7	$582.2	$146.5	34%
Operating Statistics				
Refined products:				
Transportation revenue per barrel shipped	$1.230	$1.313		
Volume shipped (million barrels):				
Gasoline	223.7	239.7		
Distillates	136.7	146.5		
Aviation fuel	21.5	21.1		
Liquefied petroleum gases	8.5	7.8		
Total volume shipped	390.4	415.1		
Crude oil:				
Transportation revenue per barrel shipped	$0.305	$0.880		
Volumes shipped (million barrels)	72.0	113.2		
Crude oil terminal average utilization (million barrels per month)	12.6	12.3		

Marine storage:		
Marine terminal average utilization (million barrels per month)	23.8	23.0

(a) Product margin does not include depreciation or amortization expense.

Transportation and terminals revenue increased by $167.6 million, resulting from:

- an increase in refined products revenue of $77.3 million. Excluding the pipeline systems we acquired in 2013, refined products revenue increased $65.3 million primarily due to a 3% increase in transportation volumes and higher rates. Shipments were higher primarily due to increased demand for gasoline and distillates. The average rate per barrel increased due to the mid-year 2012 and 2013 tariff rate increases of 8.6% and 4.6%, respectively;

- an increase in crude oil revenue of $86.1 million primarily due to crude oil deliveries from our Longhorn pipeline, which represented approximately 85% of the increase. Our Longhorn pipeline began delivering crude oil in 2013 and averaged approximately 125,000 barrels per day since its mid-April start date. We also benefited from higher utilization on our Houston-area crude oil distribution system and additional condensate throughput at our Corpus Christi terminal; and

- an increase in marine storage revenue of $4.2 million primarily due to new storage placed into service at our Galena Park, Texas terminal since late 2012 and higher throughput fees, partially offset by lower utilization mainly due to additional integrity work during the 2013 period.

Affiliate management fee revenue increased $12.6 million, primarily resulting from a full year of construction management fees received from BridgeTex in 2013, compared to one month of fees received in 2012. The construction management fees we receive are designed to reimburse us for our costs of providing construction services to BridgeTex.

Operating expenses increased $17.6 million, resulting from:

- an increase in refined products expenses of $3.0 million primarily due to higher asset integrity costs, compensation, power costs and property taxes, as well as $5.1 million of expenses related to operation of the pipeline systems we acquired in 2013, partially offset by higher product overages (which reduce operating expenses), lower losses on asset retirements, the 2013 favorable adjustment of an accrual for air emission fees at our East Houston terminal (see Notes to Consolidated Financial Statements, Note 17–Commitments and Contingencies for more information regarding the adjustment of this accrual) and lower environmental accruals. The higher compensation costs were due to increased employee headcount and higher bonus accruals. The higher power costs primarily reflect the increase in product shipments over 2012 and the higher property taxes are the result of asset additions and improved profitability over the past year;

- an increase in crude oil expenses of $13.9 million primarily due to costs related to the operation of our Longhorn pipeline in crude oil service in 2013, including pipeline rental costs to access product from third-party origination sources, higher personnel costs, power and integrity spending, partially offset by more favorable product overages (which reduce operating expenses); and

- an increase in marine storage expenses of $0.9 million primarily due to higher asset integrity costs in the current year resulting from additional tank work, higher insurance costs and higher property taxes, partially offset by the 2013 favorable adjustment of an accrual for potential air emission fees at our Galena Park facility (see Notes to Consolidated Financial Statements, Note 17–Commitments and Contingencies for more information regarding the adjustment of this accrual) and lower environmental accruals.

Product sales revenue primarily resulted from our butane blending activities, transmix fractionation and product gains from our independent terminals. We utilize New York Mercantile Exchange (“NYMEX”) contracts to hedge against changes in the price of petroleum products we expect to sell in the future. The period change in the mark-to-market value of these contracts that are not designated as hedges for accounting purposes, the effective portion of the change in value of matured NYMEX contracts that qualified for hedge accounting treatment and any ineffectiveness of NYMEX contracts that qualify for hedge accounting treatment are also included in product sales revenue. We use butane futures agreements to hedge against changes in the price of butane we expect to purchase in future periods. The period change in the mark-to-market value of these futures agreements, which were not designated as hedges, are included as adjustments to cost of product sales. Product margin increased $24.4 million primarily due to lower unrealized losses on NYMEX contracts in the current year and higher profits from our butane blending activities resulting from higher volumes sold and lower butane costs. See Other Items—Commodity Derivative Agreements—Impact of Commodity Derivatives on Results of Operations below for more information about our NYMEX contracts.

Earnings of non-controlled entities increased $3.3 million primarily due to earnings of Texas Frontera, which began operations late in 2012, and higher earnings from Osage.

Depreciation and amortization expense increased $14.2 million in 2013 primarily due to expansion capital projects and acquisitions placed into service over the past two years.

G&A expense increased $23.2 million between periods primarily due to higher personnel costs resulting from an increase in employee headcount and an increase in the current year bonus accrual resulting from above-target payout estimates, higher equity-based compensation costs due to above-target payout estimates and a higher price for our limited partner units and higher legal costs related to acquisitions we closed in 2013.

Interest expense, net of interest income and interest capitalized, increased $4.1 million in 2013. Our average outstanding debt increased from $2.2 billion in 2012 to $2.5 billion in 2013 primarily due to borrowings for expansion capital expenditures, including $250.0 million of 4.20% senior notes issued in November 2012 and $300.0 million of 5.15% senior notes issued in October 2013. Our weighted-average interest rate decreased slightly from 5.3% at December 31, 2012 to 5.2% at December 31, 2013.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2012

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2011	2012	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenue:				
Refined products	$680.3	$723.8	$43.5	6%
Crude oil	61.2	92.3	31.1	51%
Marine storage	151.9	154.6	2.7	2%
Total transportation and terminals revenue	893.4	970.7	77.3	9%
Affiliate management fee revenue	0.8	2.0	1.2	150%
Operating expenses:				
Refined products	250.8	267.7	(16.9)	(7)%
Crude oil	(4.9)	5.2	(10.1)	n/a
Marine storage	63.4	58.5	4.9	8%
Intersegment eliminations	(2.9)	(2.9)	—	—
Total operating expenses	306.4	328.5	(22.1)	(7)%
Product margin:				
Product sales	854.5	799.4	(55.1)	(6)%
Cost of product sales	706.3	657.1	49.2	7%
Product margin [(a)]	148.2	142.3	(5.9)	(4)%
Earnings of non-controlled entities	6.8	3.0	(3.8)	(56)%
Operating margin	742.8	789.5	46.7	6%
Depreciation and amortization expense	121.2	128.0	(6.8)	(6)%
G&A expense	98.7	109.4	(10.7)	(11)%
Operating profit	522.9	552.1	29.2	6%
Interest expense (net of interest income and interest capitalized)	105.6	111.7	(6.1)	(6)%
Debt placement fee amortization	1.8	2.1	(0.3)	(17)%
Income before provision for income taxes	415.5	438.3	22.8	5%
Provision for income taxes	1.9	2.6	(0.7)	(37)%
Net income	$413.6	$435.7	$22.1	5%
Operating Statistics				
Refined products:				
Transportation revenue per barrel shipped	$1.175	$1.230		
Volume shipped (million barrels):				
Gasoline	208.9	223.7		
Distillates	136.0	136.7		
Aviation fuel	25.3	21.5		
Liquefied petroleum gases	4.9	8.5		
Total volume shipped	375.1	390.4		
Crude oil:				
Transportation revenue per barrel shipped	$0.275	$0.305		
Volumes shipped (million barrels)	43.2	72.0		
Crude oil terminal average utilization (million barrels per month)	9.3	12.6		

Marine storage:		
Marine terminal average utilization (million barrels per month)	24.7	23.8

(a) Product margin does not include depreciation or amortization expense.

Transportation and terminals revenue increased by $77.3 million, resulting from:

- an increase in refined products revenue of $43.5 million resulting primarily from increases in the average per-barrel tariff rate principally reflecting the 6.9% and 8.6% tariff rate increases we implemented on July 1, 2011 and July 1, 2012, respectively, partially offset by more South Texas movements, which ship at a lower rate than our other shipments. We further benefited from higher transportation volumes between periods;

- an increase in crude oil revenue of $31.1 million primarily due to additional revenue from leasing tanks constructed throughout 2011, including new crude oil storage at Cushing, Oklahoma, and a 67% increase in shipments on our Houston-area crude oil distribution system resulting from deliveries to additional locations that have been connected to our pipeline system and increased deliveries to existing customers; and

- an increase in marine storage revenue of $2.7 million primarily due to increased demand at our Galena Park, Texas terminal.

Operating expenses increased $22.1 million, resulting from:

- an increase in refined products expenses of $16.9 million primarily due to an increase in property taxes, lower product overages (which reduce operating expenses), additional asset integrity work, higher personnel costs and higher losses on various asset retirements and replacements, partially offset by lower costs resulting from an accrual recognized in 2011 related to potential air emission fees with no corresponding charge in the 2012 period;

- an increase in crude oil expenses of $10.1 million primarily due to lower product overages (which reduce operating expenses) and higher personnel and asset integrity costs; and

- a decrease in marine storage expenses of $4.9 million primarily due to an accrual recognized in 2011 for potential air emission fees with no corresponding charge in the 2012 period, partially offset by higher losses on various asset retirements and replacements and higher operating taxes.

Product margin decreased $5.9 million primarily due to unrealized losses on NYMEX contracts in 2012 (compared to unrealized gains in 2011) resulting from increasing product prices in 2012, partially offset by increased volumes and profits from our butane blending activities primarily as a result of expanding our blending operations, particularly at our East Houston terminal. See Other Items–Commodity Derivative Agreements below for more information about our NYMEX contracts.

Earnings of non-controlled entities decreased $3.8 million from 2011 primarily due to settlement of a tariff claim against Osage.

Depreciation and amortization expense increased $6.8 million primarily due to expansion capital projects placed into service over the prior two years.

G&A expense increased $10.7 million primarily due to higher personnel costs and an increase in long-term equity-based incentive compensation costs resulting from above-target payout estimates and a higher price for our limited partner units.

Interest expense, net of interest income and interest capitalized, increased $6.1 million. Our average outstanding debt increased to $2.2 billion for 2012 from $2.1 billion for 2011 primarily due to borrowings for expansion capital expenditures, including $250.0 million of 4.25% senior notes issued in August 2011 and $250.0 million of 4.20% senior notes issued in November 2012. Our weighted-average interest rate of 5.3% at December 31, 2012 was essentially unchanged from our weighted-average interest rate at December 31, 2011.

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Distributable Cash Flow

Distributable cash flow ("DCF") and Adjusted EBITDA are non-GAAP measures. Management uses DCF as a basis for recommending to our general partner's board of directors the amount of cash distributions to be paid each period. Management also uses DCF to evaluate our ability to generate cash for distribution to our limited partners and as a basis for determining equity-based compensation. Adjusted EBITDA is an important measure that we and the investment community use to assess the financial results of an entity. We believe that investors benefit from having access to the same financial measures utilized by management for these evaluations. A reconciliation of DCF and Adjusted EBITDA for the years ended December 31, 2011, 2012 and 2013 to net income, which is their nearest comparable GAAP financial measure, is as follows (in millions):

	Year Ended December 31,		
	2011	2012	2013
Net income	$413.6	$435.7	$582.2
Interest expense, net	105.6	111.7	115.8
Depreciation and amortization[(1)]	123.0	130.1	144.7
Equity-based incentive compensation expense[(2)]	10.2	8.0	11.8
Asset retirements and impairments	8.6	12.6	7.8
Commodity-related adjustments:			
Derivative losses (gains) recognized in the period associated with future product transactions[(3)]	(5.9)	6.4	8.1
Derivative (losses) gains recognized in previous periods associated with product sales completed in the period[(4)]	(15.2)	3.7	(6.4)
Lower-of-cost-or-market adjustment	1.0	1.0	(2.0)
Houston-to-El Paso cost of sales adjustments[(5)]	(2.3)	1.8	—
Total commodity-related adjustments	(22.4)	12.9	(0.3)
Other	(2.5)	4.9	(0.4)
Adjusted EBITDA	636.1	715.9	861.6
Interest expense, net	(105.6)	(111.7)	(115.8)
Maintenance capital (net of reimbursements)	(70.0)	(64.4)	(76.1)
DCF	$460.5	$539.8	$669.7

(1) Depreciation and amortization includes debt placement fee amortization.

(2) As we intend to satisfy vesting of units under our equity-based incentive compensation program with the issuance of limited partner units, expenses related to this program generally are deemed non-cash and added back for DCF purposes. Total equity-based incentive compensation expense for the years ended December 31, 2011, 2012 and 2013 was $17.6 million, $21.0 million and $24.1 million, respectively. However, the figures above include an adjustment for minimum statutory tax withholdings we paid in 2011, 2012 and 2013 of $7.4 million, $13.0 million and $12.3 million, respectively, for equity-based incentive compensation units that vested on the previous year end, which reduce DCF.

(3) Certain derivatives we use as economic hedges have not been designated as hedges for accounting purposes and the mark-to-market changes for the derivatives are recognized currently in earnings. These amounts represent the gains or losses from economic hedges recognized in our earnings during the period associated with products that had not yet been physically sold as of the period end date.

(4) When we physically sell products that are economically hedged (but were not designated as hedges for accounting purposes), we include in our DCF calculations the full amount of the change in fair value of the associated derivative agreement.

(5)

Cost of sales adjustment related to commodity activities for our Houston-to-El Paso pipeline section to more closely resemble current market prices for DCF purposes rather than average inventory costing as used to determine our results of operations. As of December 31, 2012, we no longer perform this activity.

DCF increased $79.3 million between 2011 and 2012 and increased $129.9 million between 2012 and 2013. The change in net income and depreciation and amortization is discussed in detail in Results of Operations above, the change in equity-based compensation is discussed in footnote 2 to the table above and a discussion of our maintenance capital expenditures is provided in Capital Requirements below. The change in DCF from commodity-related adjustments is primarily due to the impact of product price changes during each period on economic hedges that do not qualify for hedge accounting treatment and the discontinuance of our Houston-to-El Paso linefill management activities in 2012.

A reconciliation of DCF to distributions paid is as follows (in millions):

	For the Year Ended December 31,		
	2011	2012	2013
Distributable cash flow	$460.5	$539.8	$669.7
Less: Cash reserves approved by our general partner	109.6	136.3	194.2
Total cash distributions paid	$350.9	$403.5	$475.5

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $577.3 million, $645.1 million and $772.7 million for the years ended December 31, 2011, 2012 and 2013, respectively.

- The $127.6 million increase from 2012 to 2013 was primarily attributable to:

a $160.8 million increase in net income and non-cash depreciation and amortization expense;
a $13.2 million increase resulting from a $2.0 million increase in accounts payable in 2013 versus a $11.2 million decrease in accounts payable in 2012, primarily due to the timing of invoices paid to vendors and suppliers; and
a $10.4 million increase resulting from a $16.8 million increase in deferred revenue in 2013 versus a $6.4 million increase in deferred revenue in 2012. The increase in 2013 was primarily due to an increase related to customers' transportation deficiencies where our customers have the right to apply these deferrals against future product shipments and a deferral of a sale of an asset where the title had not yet passed, but the cash had been received.
These increases were partially offset by:
a $21.2 million decrease resulting from a $9.0 million decrease in accrued product purchases in 2013 versus a $12.2 million increase in accrued product purchases in 2012, primarily due to the timing of invoices paid to vendors and suppliers and lower butane prices in 2013;
a $15.6 million decrease resulting from a $0.5 million increase in energy commodity derivatives contracts, net of derivatives deposits, in 2013 versus a $16.1 million increase in 2012 primarily due to the impact of changes in commodity prices on our economic hedges; and
a $10.8 million decrease resulting from a $12.2 million decrease in current and noncurrent environmental liabilities in 2013 versus a $1.4 million decrease in current and noncurrent environmental liabilities in 2012, primarily due to an adjustment during 2013 of an accrual for potential air emission fees at our East Houston and Galena Park facilities (see Environmental below for more information regarding the adjustment of this accrual).

- The $67.8 million increase from 2011 to 2012 was primarily attributable to:

a $28.9 million increase in net income and non-cash depreciation and amortization expense;

a $79.5 million increase primarily resulting from higher prices and volumes of inventory purchases in 2011 as compared to 2012; specifically, a $37.0 million decrease in inventory in 2012, primarily due to the sale of our Houston-to-El Paso pipeline section linefill working inventory, versus a $42.5 million increase in inventory in 2011; and

a $35.9 million increase resulting from a $16.1 million increase in cash from energy commodity derivatives contracts, net of derivatives deposits in 2012, versus a $19.8 million decrease in 2011 primarily due to lower product prices and a decrease in the number of NYMEX commodity contracts during 2012.

These increases were partially offset by:

a $31.4 million decrease resulting from a $11.2 million decrease in accounts payable in 2012 versus a $20.2 million increase in accounts payable in 2011 primarily due to the timing of invoices paid to vendors and suppliers;

an $18.3 million decrease resulting from a $1.4 million decrease in current and noncurrent environmental liabilities in 2012 versus a $16.9 million increase in current and noncurrent environmental liabilities in 2011 primarily due to potential air emission fees accrued in 2011 related to potential air emission fees at our East Houston and Galena Park facilities (see Environmental below for further details regarding this matter);

a $16.7 million decrease resulting from a $10.9 million increase in trade accounts receivable and other accounts receivable in 2012 versus a $5.8 million decrease during 2011 primarily due to timing of payments from our customers; and

a $14.4 million decrease due to a change in restricted cash. During first quarter 2011, we acquired the non-controlling owner's interest in one of our subsidiaries, which removed our restriction to that entity's cash. As a result of that transaction, cash from operations increased $14.4 million in 2011.

Net cash used by investing activities for the years ended December 31, 2011, 2012 and 2013 was $258.7 million, $368.1 million and $882.0 million, respectively. During 2013, we spent $383.8 million for capital expenditures, which included $76.1 million for maintenance capital and $307.7 million for expansion capital. Our expansion capital spending during 2013 was primarily for the Longhorn pipeline reversal project. Also during 2013, we contributed capital of $250.5 million in conjunction with our joint venture capital projects which we account for as investments in non-controlled entities, acquired approximately 800 miles of refined petroleum products pipelines for $192.0 million and spent $22.5 million on an asset acquisition. During 2012, we spent $354.2 million for capital expenditures, which included $64.4 million for maintenance capital and $289.8 million for expansion capital. Also during 2012, we contributed capital of $74.9 million in conjunction with our joint venture capital projects which we account for as investments in non-controlled entities. During 2011, we spent $199.7 million for capital expenditures, which included $70.0 million for maintenance capital and $129.7 million for expansion capital. Also during 2011, we acquired a private investment group's common equity in Magellan Crude Oil, LLC for $40.5 million, spent $17.8 million on various asset acquisitions and contributed capital of $8.1 million in conjunction with our joint venture capital projects which we account for as investments in non-controlled entities.

Net cash used by financing activities for the years ended December 31, 2011, 2012 and 2013 was $116.4 million, $158.4 million and $193.7 million, respectively. During 2013, we paid cash distributions of $475.5 million to our unitholders. Additionally, we received net proceeds of $298.7 million from borrowings under notes, which were used to repay borrowings outstanding under our revolving credit facility and for general partnership purposes, including growth capital spending and acquisitions. Also, in 2013, the cumulative amounts of the 2010 equity-based incentive compensation award grants were settled by issuing 476,682 limited partner units and distributing those units to the participants, resulting in payments of associated tax withholdings of $12.3 million. During 2012, we paid cash distributions of $403.5 million to our unitholders. Additionally, we received net proceeds of $248.3 million from borrowings under notes, which were used for expansion capital projects. Also, in 2012, the cumulative amounts of the 2009 equity-based incentive compensation award grants were settled by issuing 722,766 limited partner units and distributing those units to the participants, resulting in payments of associated tax withholdings of $13.0 million. During 2011, we paid cash distributions of $350.9 million to our unitholders. We received net proceeds of $260.9 million from borrowings under notes, which were used to repay the outstanding balance on our revolving credit facility of $193.0 million at that time, with the balance used for general partnership purposes. Additionally, borrowings on our revolving credit facility of $178.0 million, prior to being repaid, were primarily used to finance expansion capital projects and acquisitions.

The quarterly distribution amount related to fourth quarter 2013 was $0.585 per unit, which was paid in February 2014. If we are able to meet management's targeted distribution growth of 20% during 2014 and the number of outstanding limited partner units remains at 227.1 million, total cash distributions of approximately $593.5 million will be paid to our unitholders related to 2014. Management believes we will have sufficient distributable cash flow to fund these distributions.

Capital Requirements

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

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

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

During 2013, our maintenance capital spending was $76.1 million. For 2014, we expect to spend approximately $77.0 million on maintenance capital.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities and acquire new assets. During 2013, we spent $307.7 million for organic growth capital and $250.5 million for growth projects in conjunction with our joint venture capital projects. Additionally, we spent $214.5 million on business and asset acquisitions. Based on the progress of expansion projects already underway, including the expansion of our Longhorn crude oil pipeline and our investment in the BridgeTex pipeline, we expect to spend approximately $550.0 million for expansion capital during 2014.

Liquidity

Cash generated from operations is our primary source of liquidity for funding debt service, maintenance capital expenditures and quarterly distributions. Additional liquidity for purposes other than quarterly distributions, such as expansion capital expenditures and debt repayments, is available through borrowings under our revolving credit facility discussed below, as well as from other borrowings or issuances of debt or limited partner units. If capital markets do not permit us to issue additional debt and equity securities, our business may be adversely affected, and we may not be able to acquire additional assets and businesses, fund organic growth projects or repay our debts when they become due.

Our debt at December 31, 2012 and 2013 was as follows (in thousands):

	December 31, 2012	2013	Weighted-Average Interest Rate at December 31, 2013 (a)
Revolving credit facility	$—	$—	—%
$250.0 million of 6.45% Notes due 2014	249,905	249,971	6.3%
$250.0 million of 5.65% Notes due 2016	251,609	251,183	5.7%
$250.0 million of 6.40% Notes due 2018	261,411	259,346	5.4%
$550.0 million of 6.55% Notes due 2019	575,065	571,515	5.7%
$550.0 million of 4.25% Notes due 2021	558,088	557,213	4.0%
$250.0 million of 6.40% Notes due 2037	248,981	248,998	6.4%
$250.0 million of 4.20% Notes due 2042	248,349	248,377	4.2%
$300.0 million of 5.15% Notes due 2043	—	298,684	5.2%
Total debt	$2,393,408	$2,685,287	5.2%

(a) Weighted-average interest rate includes the amortization/accretion of discounts and premiums and the amortization/accretion of gains and losses realized on historical cash flow and fair value hedges (see Note 13—Derivative Financial Instruments for detailed information regarding fair value hedges and interest rate swaps).

The revolving credit facility and notes detailed in the table above are senior indebtedness.

The face value of our debt at December 31, 2012 and 2013 was $2.4 billion and $2.7 billion, respectively. The difference between the face value and carrying value of the debt outstanding is the unamortized portion of terminated fair value hedges and the unamortized discounts and premiums on debt issuances. Realized gains and losses on fair value hedges and note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of those notes. At December 31, 2013, maturities of our debt were as follows: $250.0 million in 2014; $0 in 2015; $250.0 million in 2016; $0 in 2017; $250.0 million in 2018; and $1.9 billion thereafter.

2013 Debt Offering

In October 2013, we issued $300.0 million of 5.15% notes due October 15, 2043 in an underwritten public offering. The notes were issued for the discounted price of 99.6% of par. We used the net proceeds from this offering of approximately $295.6 million, after underwriting discounts and offering expenses of $3.1 million, to repay borrowings outstanding under our revolving credit facility and for general partnership purposes, including expansion capital.

Other Debt

Revolving Credit Facility. During November 2013, we amended our revolving credit facility, increasing the borrowing capacity from $800.0 million to $1.0 billion and extending the maturity date from October 2016 to November 2018. In connection with this amendment, we incurred $1.7 million of debt placement fees and wrote off $0.2 million of unamortized debt placement fees associated with the original revolving credit facility. Borrowings under our revolving credit facility are unsecured and bear interest at LIBOR plus a spread ranging from 1.0% to 1.75% based on our credit ratings. At December 31, 2013, our borrowing rate under the facility was LIBOR plus 1.125%. Additionally, an unused commitment fee is assessed at a rate from 0.10% to 0.28%, depending on our credit ratings. Our unused commitment fee was 0.125% at December 31, 2013. Borrowings under this facility may be used for general purposes, including capital expenditures. As of December 31, 2013, there were no borrowings outstanding under this facility with $5.6 million obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets, but decrease our borrowing capacity under the facility.

The revolving credit facility described above requires us to maintain a specified ratio of consolidated debt to EBITDA (as defined in the credit agreement) of no greater than 5.0 to 1.0. In addition, the revolving credit facility and the indentures under which our senior notes were issued contain covenants that limit our ability to, among other things, incur indebtedness secured by certain liens or encumber our assets, engage in certain sale-leaseback transactions and consolidate, merge or dispose of all or substantially all of our assets. We were in compliance with these covenants as of and during the year ended December 31, 2013.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2013 (in millions):

	Total	< 1 year	1-3 years	3-5 years	> 5 years
Long-term debt obligations(1)	$2,650.0	$250.0	$250.0	$250.0	$1,900.0
Interest obligations	1,622.6	139.2	262.3	229.7	991.4
Operating lease obligations	130.0	16.2	32.6	29.7	51.5
Pension and postretirement medical obligations(2)	52.2	20.4	22.5	1.8	7.5
Purchase commitments:					
Product purchase commitments	126.2	93.7	32.5	—	—
Utility purchase commitments	11.8	6.7	4.7	0.4	—
Derivative instruments(3)	—	—	—	—	—
Equity-based incentive awards(4)	59.4	20.5	38.9	—	—
Environmental remediation(5)	6.0	1.9	3.1	1.0	—
Capital project purchase obligations	71.3	71.3	—	—	—
Maintenance obligations	39.4	39.2	0.2	—	—
Other purchase obligations	2.5	1.9	0.5	0.1	—
Total	$4,771.4	$661.0	$647.3	$512.7	$2,950.4

(1) At December 31, 2013, we had no borrowings outstanding under our revolving credit facility. For purposes of this table, we have reflected no assumed borrowings under our revolving credit facility for any periods presented.

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

(3) As of December 31, 2013, we had entered into commodity-related derivative contracts representing 2.9 million barrels of petroleum products that we expect to sell in the future and 0.1 million barrels of butane we expect to purchase in the future. At December 31, 2013, we had recorded a net liability of $4.5 million and made margin deposits of $14.8 million associated with these derivative agreements. We have excluded from this table the future net cash outflows, if any, under these derivative agreements and the amounts of future margin deposit requirements because those amounts are uncertain.

(4) Represents the grant date fair value of unit awards accounted for as equity plus the December 31, 2013 re-measured grant date fair value of award grants accounted for as liabilities. The total equity-based incentive awards liability is determined by multiplying the grant date per unit fair value by the number of unit award grants, multiplied by the percentage of the requisite service period completed, multiplied by the estimated payout percentage of the awards at December 31, 2013. Settlements of these awards will differ from these reported amounts primarily due to differences between actual and current estimates of payout percentages and forfeitures, changes in our unit price between December 31, 2013 and the vesting dates of the awards and completion of the remaining portion of the requisite service periods.

(5) During 2005, we entered into a 10-year agreement to reach contractual endpoint (as defined in the agreement) for 23 remediation sites. This contract obligated us to pay the remediation costs incurred by the contract counterparty associated with these 23 sites up to a maximum of $14.3 million. The amounts in the table above include the

estimated remaining amounts to be paid under this agreement ($0.9 million as of December 31, 2013) and the estimated timing of these payments. Additionally, this agreement required us to pay the contract counterparty a performance bonus if the remediation sites are brought to contractual endpoint for less than $14.3 million. The table above includes our estimate of the performance bonus ($1.1 million as of December 31, 2013). During 2006, we entered into a separate 10-year agreement with an independent contractor to remediate certain of our environmental sites. This contract obligated us to pay $16.2 million over a 10-year period. The amounts in the table above include the remaining amounts to be paid under this agreement ($4.0 million as of December 31, 2013) and the estimated timing of those payments based on project progress to date.

Environmental

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

Clean Air Act - Section 185 Liability

Section 185 of the Clean Air Act ("CAA 185") requires states to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas that did not meet the attainment deadline. The CAA 185 fees are required annually until the area is redesignated as an attainment area for ozone. The Houston-Galveston region was determined to be a severe nonattainment area that did not meet its 2007 attainment deadline and, as such, would be subject to CAA 185.

During 2011, the Texas Commission on Environmental Quality (“TCEQ”) had published notices concerning its intention to issue a “Failure to Attain Rule” to implement the requirements of CAA 185. At that time, management believed it was probable that the TCEQ’s Failure to Attain Rule would provide for the collection of annual failure to attain fees for excess emissions for the annual periods from 2008 through 2011. We have certain facilities in the Houston area that would have been subject to these rules; therefore, we recognized a $10.9 million environmental liability during 2011 as our estimate of excess emission fees we would be required to pay under the rules.

In June 2013, the TCEQ adopted its Failure to Attain Rule which did not require retroactive assessment of the Section 185 fees for the annual periods of 2008 through 2011. As a result, during 2013, in accordance with the TCEQ's final rule, we reduced our accrual by $10.6 million.

Other Items

Commodity Derivative Agreements. Certain of the business activities in which we engage result in our owning various commodities which exposes us to commodity price risk. We use NYMEX contracts and butane futures agreements to help manage this commodity price risk. We use NYMEX contracts to hedge against changes in the price of refined products we expect to sell in future periods. We use and account for those NYMEX contracts that qualify for hedge accounting treatment as either cash flow or fair value hedges, and we use and account for those NYMEX contracts that do not qualify for hedge accounting treatment as economic hedges. We use butane futures agreements to economically hedge against changes in the price of butane we expect to purchase in the future as part of our butane blending activity. As of December 31, 2013, our open derivative contracts were as follows:

Open Derivative Contracts Designated as Hedges

- NYMEX contracts covering 0.7 million barrels of crude oil to hedge against future price changes of crude oil linefill and tank bottom inventory. These contracts, which we are accounting for as fair value hedges, mature between January 2014 and November 2016. Through December 31, 2013, the cumulative amount of losses from these agreements was $8.7 million. The cumulative losses from these fair value hedges were recorded as adjustments to the asset being hedged, and there has been no ineffectiveness recognized for these hedges. As a result, none of these cumulative losses have impacted our consolidated income statement.

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Open Derivative Contracts Not Designated as Hedges

- NYMEX contracts covering 1.9 million barrels of refined products related to our butane blending and fractionation activities. These contracts mature between January and April 2014 and are being accounted for as economic hedges. Through December 31, 2013, the cumulative amount of net unrealized losses associated with these agreements was $6.8 million. We recorded these losses as an adjustment to product sales revenue, all of which was recognized in 2013.

- NYMEX contracts covering 0.3 million barrels of refined products and crude oil related to inventory we carry that resulted from pipeline product overages. These contracts, which mature in January and February 2014, are being accounted for as economic hedges. Through December 31, 2013, the cumulative amount of unrealized losses associated with these agreements was $0.2 million. We recorded these losses as an increase in operating expenses, all of which was recognized in 2013.

- Butane futures agreements to purchase 0.1 million barrels of butane that mature between January and April 2014, which are being accounted for as economic hedges. Through December 31, 2013, the cumulative amount of unrealized gains associated with these agreements was $0.4 million. We recorded these gains as a decrease in cost of product sales, all of which was recognized in 2013.

Settled Derivative Contracts

- We settled NYMEX contracts covering 8.2 million barrels of refined products related to economic hedges of products from our butane blending and fractionation activities that we sold during 2013. We recognized a gain of $0.6 million in 2013 related to these contracts which we recorded as an adjustment to product sales revenue.

- We settled NYMEX contracts covering 0.2 million barrels of refined products related to cash flow hedges of products from our butane blending and fractionation activities that we sold during 2013. We recognized a loss of $4.4 million on the settlement of these contracts which we recorded as an adjustment to product sales revenue.

- We settled NYMEX contracts covering 5.3 million barrels of refined products and crude oil related to economic hedges of product inventories from product overages on our pipeline systems which we sold during 2013. We recognized a loss of $3.6 million in 2013 on the settlement of these contracts which we recorded as an adjustment to operating expense.

- We settled butane futures agreements covering 0.5 million barrels related to economic hedges of butane purchases we made during 2013 associated with our butane blending activities. We recognized a gain of $2.3 million in 2013 on the settlement of these contracts which we recorded as an adjustment to cost of product sales.

Impact of Commodity Derivatives on Results of Operations

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

	Year Ended December 31, 2012			
	Product Sales	Cost of Product Sales	Operating Expense	Net Impact on Results of Operations
NYMEX gains (losses) recognized during the period that were associated with economic hedges of physical product sales or purchases during the period	$(30.5)	$0.1	$0.1	$(30.3)
NYMEX gains from cash flow hedges that were reclassified from accumulated other comprehensive loss during the period	2.8	—	—	2.8
NYMEX gains (losses) recorded during the period that were associated with products that will be or were sold or purchased in future periods	(6.5)	1.1	(2.2)	(7.6)
Net gain (loss) on NYMEX contracts	$(34.2)	$1.2	$(2.1)	$(35.1)

	Year Ended December 31, 2013			
	Product Sales	Cost of Product Sales	Operating Expense	Net Impact on Results of Operations
NYMEX gains (losses) recognized during the period that were associated with economic hedges of physical product sales or purchases during the period	$0.6	$2.3	$(3.6)	$(0.7)
NYMEX losses from cash flow hedges that were reclassified from accumulated other comprehensive loss during the period	(4.4)	—	—	(4.4)
NYMEX gains (losses) recorded during the period that were associated with products that will be or were sold or purchased in future periods	(6.8)	0.4	(0.2)	(6.6)
Net gain (loss) on NYMEX contracts	$(10.6)	$2.7	$(3.8)	$(11.7)

Pipeline Tariff Increase. The FERC regulates the rates charged on interstate common carrier pipeline operations primarily through an indexing methodology, which establishes the maximum amount by which tariffs can be adjusted each year. Approximately 40% of our refined products tariffs are subject to this indexing methodology while the remaining 60% of our refined products tariffs can be adjusted at our discretion based on competitive factors. The FERC-approved indexing method to be used for the five-year period beginning in July 2011 is the annual change in the producer price index for finished goods (“PPI-FG”) plus 2.65%. Based on this indexing methodology, we expect to increase virtually all of our refined products tariffs by approximately 4.0% on July 1, 2014. Further, pursuant to our customer contracts, we intend to increase our tariffs on the Longhorn crude pipeline by 5% on July 1, 2014.

Critical Accounting Estimates

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

Environmental Liabilities

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

A defined process for project review is integrated into our system integrity plan. Each year our remediation project managers meet to evaluate, in detail, the known environmental sites. The purpose of the annual project review is to assess all aspects of each project, evaluating what actions will be required to achieve regulatory compliance and estimating the costs and timing to execute the regulatory phases that can be reasonably estimated. During the site-specific evaluations, we utilize all known information in conjunction with professional judgment and experience to determine the appropriate approach to remediation and to assess liabilities. The process to achieve regulatory compliance consists of site investigation/delineation, site remediation and long-term monitoring. Each of these phases can, and often does, include unknown variables that complicate the task of evaluating the estimated costs to completion. At each accounting period-end we re-evaluate our environmental estimates taking into account any new incidents that have occurred since the last annual meeting of the remediation project managers, any changes in the site situation remediation, including work to date, additional findings or changes in federal or state regulations and changes in cost estimates. Changes in our environmental liabilities since December 31, 2011 were as follows (in millions):

Balance 12/31/11	2012 Accruals	Expenditures	Balance 12/31/12	2013 Accruals	Expenditures	Balance 12/31/13
$49.6	$13.2	$(14.5)	$48.3	$(1.6)	$(8.2)	$38.5

During 2012, we increased our environmental liability accruals by $13.2 million, of which $5.2 million was due to product releases which occurred during 2012 and $8.0 million related to historical releases. At December 31, 2012, we had recognized $7.9 million of receivables from insurance carriers associated with environmental claims.

During 2013, we decreased our environmental liability accruals by $1.6 million, which included a $10.6 million favorable adjustment related to a Section 185 CAA contingent liability accrual we initially recognized in 2011 (see Note 17–Commitments and Contingencies to our consolidated financial statements for further details regarding this adjustment). Excluding this adjustment, during 2013, we increased our environmental liability accruals $9.0 million, of which $2.5 million were environmental liabilities assumed in acquisitions, $0.4 million related to additional Section 185 CAA fee accruals, $0.3 million was due to product releases which occurred during 2013 and $5.8 million related to historical releases. At December 31, 2013, we had recognized $4.8 million of receivables from insurance carriers associated with environmental claims.

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

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Pension and Postretirement Obligations

We sponsor two union pension plans covering certain employees (“USW plan” and “IUOE plan”), a pension plan for all non-union employees (“Salaried plan”) and a postretirement benefit plan for certain employees. Various estimates and assumptions directly affect net periodic benefit expense and obligations for these plans. These estimates and assumptions include the expected long-term rates of return on plan assets, discount rates, expected rate of compensation increase and the assumed health care cost trend rate. Management reviews these assumptions annually and makes adjustments as necessary.

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

	Benefit Expense		Benefit Obligation	
	One-Percentage-Point Increase	One-Percentage-Point Decrease	One-Percentage-Point Increase	One-Percentage-Point Decrease
Pension benefits:				
Discount rate	$ (3,102)	$ 4,014	$ (18,030)	$ 22,802
Expected long-term rate of return on plan assets	(998)	998	—	—
Rate of compensation increase	1,888	(1,888)	8,014	(8,014)
Other postretirement benefits:				
Discount rate	(77)	166	(1,115)	1,364
Assumed health care cost trend rate	131	(53)	533	(485)

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

	One-Percentage-Point Decrease	One-Percentage-Point Increase
Projected return on assets	$79	$(79)
Rate of compensation increase	$(2,589)	$2,589

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

We estimate the long-term expected rate of return on plan assets using expectations of capital market results, which includes an analysis of historical results as well as forward-looking projections. We base these capital market expectations on a long-term period and on our investment strategy and asset allocation. We develop our estimates using input from several external sources, including consultation with our third-party independent investment consultant. We develop the forward-looking capital market projections using a consensus of expectations by economists for inflation and dividend yield, along with expected changes in risk premiums. Because our determined rate is an estimate of future results, it could be significantly different from actual results.

The capital markets have improved substantially since 2008 and the benefit plans' assets reflect these improvements. While the 2012 benefit investment performance was greater than our expected rate of return for that year, the investment performance for 2011 and 2013 was 4.2% and 3.0%, respectively, less than our expected rates of return. The expected rates of return on plan assets are long-term in nature; therefore, short-term market performance does not significantly affect these rates. Changes to our asset allocation also affect these expected rates of return. The expected long-term rate of return on plan assets used for our Salaried and USW plans has been approximately 7.0% since 2004. For 2011, we estimated the long-term rate of return on the IUOE plan assets at

3.3% primarily due to the asset allocation of that fund at that time; however, with the changes in asset allocations for the fund over the past years, we increased this rate to be in line with the Salaried and USW plans for 2012 and 2013. The 2013 actual return on plan assets for our Salaried, USW and IUOE pension plans was a gain (loss) of approximately 6.4%, (0.4)% and 7.3%, respectively. Through December 2013, the weighted-average rate of return on pension plan assets for the ten-year period we have controlled the plans was approximately 5.6%, which was significantly affected by the 14.2% loss experienced in 2008.

The expected rate of compensation increase represents average long-term salary increases. An increase in this rate causes the pension obligation and expense to increase. We base the assumed health care cost trend rates on national trend rates adjusted for our actual historical claims experience and plan design. An increase in this rate causes the other postretirement benefit obligation and expense to increase.

Valuation of Assets

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

During 2013, we completed an acquisition accounted for as a business combination for $192.0 million. For all significant acquisitions, we engage the services of an independent appraiser to assist us in determining the fair value of the acquired assets and liabilities, including goodwill; however, the ultimate determination of those values is the responsibility of our management. We base our estimates on assumptions believed to be reasonable, but which are inherently uncertain. These valuations require the use of management’s assumptions, which would not reflect unanticipated events and circumstances that may occur.

Goodwill and Impairment of Long-Lived Assets

Goodwill. At December 31, 2012 and 2013, we had recognized goodwill of $53.3 million. Goodwill resulting from a business combination is not subject to amortization; however, we test goodwill for impairment annually or more frequently when indicators of impairment exist. As required by Accounting Standards Codification ("ASC") 350, Goodwill and Other, we test goodwill at the reporting unit level for impairment annually and between annual tests if events or changes in circumstances indicate the carrying amount may exceed fair value. Recoverability is determined by comparing the estimated fair value of a reporting unit to the carrying value, including the related goodwill, of that reporting unit using the equity premise method. We use the present value of expected net cash flows and market multiple analyses to determine the estimated fair values of our reporting segments. The impairment test under ASC 350 requires the use of projections, estimates and assumptions as to the future performance of our operations, including anticipated future revenues, expected future operating costs, discount factor and the terminal value of the reporting unit. Actual results could differ from projections resulting in revisions to our assumptions and, if required, recognizing an impairment loss. Any such impairment losses recognized could be material to our results of operations. The accounting estimate relative to assessing the impairment of goodwill is a critical accounting estimate for each of our reporting segments. Based on our assessment at December 31, 2011, 2012 and 2013, we do not believe our goodwill was impaired, and we did not record a charge associated with ASC 350 during 2011, 2012 or 2013.

Impairment of Long-Lived Assets. As prescribed by ASC 360-10-05, Property, Plant and Equipment-General-Impairment or Disposal of Long-Lived Assets, we assess property, plant and equipment ("PP&E") for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. Such indicators include, among others, the nature of the asset, the projected future economic benefit of the asset, changes in regulatory and political environments and historical and future cash flow and profitability measurements. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, we recognize an impairment charge for the excess of carrying value of the asset over its estimated fair value.

Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses and the outlook for national or regional market supply and demand conditions. We base the impairment reviews and calculations used in our impairment tests on assumptions that are consistent with our business plans and long-term investment decisions.

Impairments recognized during 2011, 2012 and 2013 were not material. An estimate as to the sensitivity to earnings for these periods had we used other assumptions in our impairment reviews and impairment calculations is not practicable, given the broad range of our PP&E and the number of assumptions involved in the estimates. Favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired.

New Accounting Pronouncements

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2013-02, Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. The amendments in ASU 2013-02 do not change the current requirements for reporting net income or other comprehensive income in financial statements. However, the amendments require an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. ASU 2013-02 became effective for annual and interim periods beginning after December 15, 2012 and was to be applied prospectively. Our adoption of this standard in the first quarter of 2013 did not have a material impact on our results of operations, financial position or cash flows.

In December 2011, the FASB issued ASU 2011-11, Disclosures about Offsetting Assets and Liabilities. This ASU requires entities that have financial instruments and derivatives that are either: (i) offset in accordance with ASC Topic 210 or Topic 815 or (ii) are subject to an enforceable master netting arrangement or similar agreement to make additional disclosures of the gross and net amounts of those assets and liabilities, the amounts offset in accordance with ASC Topics 210 and 815, as well as qualitative disclosures of the entity's master netting arrangement or similar agreement. In January 2013, the FASB issued ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. The amendments in ASU 2013-01 clarify that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with ASC Topic 815, Derivatives and Hedging. ASU 2011-11 must be applied retrospectively and became effective for fiscal years beginning on or after January 1, 2013. Our adoption of these standards in the first quarter of 2013 did not have a material impact on our results of operations, financial position or cash flows.

Related Party Transactions

Barry R. Pearl is an independent member of our general partner's board of directors and is also a director of Targa Resources Partners, L.P. ("Targa"). In the normal course of business, we purchase butane from subsidiaries of Targa. For the years ended December 31, 2011, 2012 and 2013, we made purchases of butane from subsidiaries of Targa of

$11.7 million, $27.4 million and $30.4 million, respectively. These purchases were made on the same terms as comparable third-party transactions. Amounts payable to Targa at December 31, 2012 were $0.1 million. There were no amounts payable to Targa at December 31, 2013.

In January 2011, our former chief executive officer, Don R. Wellendorf, retired. In conjunction with Mr. Wellendorf's retirement, our general partner's board of directors engaged Mr. Wellendorf as a consultant to us for a period of twelve months beginning in February 2011 for consideration of $0.3 million and an agreement that certain of his previously-awarded phantom unit awards would not be forfeited. Expense associated with these awards for the years ended December 31, 2011 and 2012 was $2.1 million and $0.5 million, respectively.

Investments in Non-Controlled Entities.

Texas Frontera. We own a 50% interest in Texas Frontera, which owns approximately one million barrels of refined products storage at our Galena Park, Texas terminal. The storage capacity owned by this venture is leased to an affiliate of Texas Frontera under a long-term lease agreement. Texas Frontera began operations in October 2012. We receive management fees from Texas Frontera, which we report as affiliate management fee revenue on our consolidated statements of income.

Osage. We own a 50% interest in Osage, which owns a 135-mile crude oil pipeline in Oklahoma and Kansas that we operate. We receive management fees from Osage, which we report as affiliate management fee revenue on our consolidated statements of income.

Double Eagle. We own a 50% interest in Double Eagle, which transports condensate from the Eagle Ford shale formation in South Texas via a 195-mile pipeline to our terminal in Corpus Christi, Texas. Double Eagle is operated by an affiliate of the other 50% member of Double Eagle. We receive connection fees from Double Eagle that are included in our transportation and terminals revenue on our consolidated statements of income. For the year ended December 31, 2013, we received connection fees of $1.4 million and recognized a $0.2 million trade accounts receivable from Double Eagle at December 31, 2013.

BridgeTex. We own a 50% interest in BridgeTex, which is in the process of constructing a 450-mile pipeline with related infrastructure to transport crude oil from Colorado City, Texas for delivery to Houston and Texas City, Texas refineries. This pipeline is expected to begin service in mid-2014. We receive construction management fees from BridgeTex, which we report as affiliate management fee revenue on our consolidated statements of income.

During 2013, we received $4.8 million from BridgeTex as a deposit for the purchase of emission reduction credits, which we expect to transfer to BridgeTex during the first half of 2014. Also in 2013, we received $1.4 million from BridgeTex for the purchase of easement rights from us, of which $0.7 million was recorded as a reduction of operating expense and $0.7 million was recorded as an adjustment to our investment in BridgeTex, which will be amortized as a reduction of operating expense over the weighted average depreciable lives of the BridgeTex assets.

Forward-Looking Statements

Certain matters discussed in this Annual Report on Form 10-K include forward-looking statements within the meaning of the federal securities laws that discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as "anticipates," "believes," "continue," "could," "estimates," "expects," "forecasts," "goal," "guidance," "intends," "may," "might," "plans," "potential," "projects," "scheduled," "should" and other similar expressions. Although we believe our forward-looking statements are based on reasonable assumptions, statements made regarding future results are not guarantees of future performance and are subject to numerous assumptions, uncertainties and risks that are difficult to predict. Therefore, actual outcomes and results may be materially different from the results stated or implied in such forward-looking statements included in this report.

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

- overall demand for refined products, crude oil, liquefied petroleum gases and ammonia in the U.S.;
- price fluctuations for refined products, crude oil, liquefied petroleum gases and ammonia and expectations about future prices for these products;
- changes in general economic conditions, interest rates and price levels;
- changes in the financial condition of our customers, vendors, derivatives counterparties, joint venture co-owners or lenders;
- our ability to secure financing in the credit and capital markets in amounts and on terms that will allow us to execute our growth strategy, refinance our existing obligations when due and maintain adequate liquidity;
- development of alternative energy sources, including but not limited to natural gas, solar power, wind power and geothermal energy, increased use of biofuels such as ethanol and biodiesel, increased conservation or fuel efficiency, as well as regulatory developments or other trends that could affect demand for our services;
- changes in the throughput or interruption in service on refined products or crude oil pipelines owned and operated by third parties and connected to our assets;
- changes in demand for storage in our refined products, crude oil or marine terminals;
- changes in supply patterns for our storage terminals due to geopolitical events;
- our ability to manage interest rate and commodity price exposures;
- changes in our tariff rates implemented by the Federal Energy Regulatory Commission, the U.S. Surface Transportation Board or state regulatory agencies;
- shut-downs or cutbacks at refineries, oil wells, petrochemical plants, ammonia production facilities or other customers or businesses that use or supply our services;
- the effect of weather patterns and other natural phenomena, including climate change, on our operations and demand for our services;
- an increase in the competition our operations encounter;
- the occurrence of natural disasters, terrorism, operational hazards, equipment failures, system failures or unforeseen interruptions;
- not being adequately insured or having losses that exceed our insurance coverage;
- our ability to obtain insurance and to manage the increased cost of available insurance;
- the treatment of us as a corporation for federal or state income tax purposes or if we become subject to significant forms of other taxation or more aggressive enforcement or increased assessments under existing forms of taxation;
- our ability to identify expansion projects or to complete identified expansion projects on time and at projected costs;
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our ability to make and integrate accretive acquisitions and joint ventures and successfully execute our business strategy;

- uncertainty of estimates, including accruals and costs of environmental remediation;

- our ability to cooperate with and rely on our joint venture co-owners;
- actions by rating agencies concerning our credit ratings;
- our ability to timely obtain and maintain all necessary approvals, consents and permits required to operate our existing assets and any new or modified assets;
- our ability to promptly obtain all necessary services, materials, labor, supplies and rights-of-way required for construction of our growth projects, and to complete construction without significant delays, disputes or cost overruns;
- risks inherent in the use and security of information systems in our business and implementation of new software and hardware;
- changes in laws and regulations that govern product quality specifications or renewable fuel obligations that could impact our ability to produce gasoline volumes through our blending activities or that could require significant capital outlays for compliance;
- changes in laws and regulations to which we or our customers are or become subject, including tax withholding issues, safety, security, employment and environmental laws and regulations, including laws and regulations designed to address climate change and laws and regulations affecting hydraulic fracturing, and laws and regulations relating to derivatives transactions;
- the cost and effects of legal and administrative claims and proceedings against us or our subsidiaries;
- the amount of our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- the effect of changes in accounting policies;
- the potential that our internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful;
- the ability of third parties to perform on their contractual obligations to us;
- petroleum product supply disruptions;
- global and domestic repercussions from terrorist activities, including cyber attacks, and the government's response thereto; and
- other factors and uncertainties inherent in the transportation, storage and distribution of refined products and crude oil.

This list of important factors is not exclusive. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events, changes in assumptions or otherwise.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

We use derivatives to help us manage commodity price risk. Forward physical contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting. As of December 31, 2013, we had commitments under forward purchase and sale contracts used in our butane blending and fractionation activities as follows (in millions):

	Notional Value	Barrels
Forward purchase contracts	$122.8	2.0
Forward sale contracts	$64.2	0.6

We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell from activities in which we acquire or produce petroleum products. Some of these NYMEX contracts qualify for hedge accounting treatment, and we designate and account for these contracts as either cash flow or fair value hedges. We account for those NYMEX contracts that do not qualify for hedge accounting treatment, or are otherwise undesignated as cash flow or fair value hedges, as economic hedges. We also use butane futures agreements to hedge against changes in the price of butane that we expect to purchase in future periods. At December 31, 2013, we had open NYMEX contracts representing 2.9 million barrels of petroleum products we expect to sell in the future. Additionally, we had open butane futures agreements for 0.1 million barrels of butane we expect to purchase in the future.

At December 31, 2013, the fair value of our open NYMEX contracts was a liability of $4.9 million and the fair value of our butane futures agreements was an asset of $0.4 million. Combined, the net liability of $4.5 million was recorded as a current liability to energy commodity derivatives contracts ($6.7 million) and other non-current assets ($2.2 million).

At December 31, 2013, open NYMEX contracts representing 2.2 million barrels of petroleum products did not qualify for hedge accounting treatment. A $10.00 per barrel increase in the price of these NYMEX contracts for reformulated gasoline blendstock for oxygen blending (“RBOB”) gasoline or heating oil would result in a $22.0 million decrease in our operating profit and a $10.00 per barrel decrease in the price of these NYMEX contracts for RBOB or heating oil would result in a $22.0 million increase in our operating profit. However, the increases or decreases in operating profit we recognize from our open NYMEX contracts would be substantially offset by higher or lower product sales revenue when the physical sale of the product occurs. These contracts may be for the purchase or sale of product in markets different from those in which we are attempting to hedge our exposure, resulting in hedges that do not eliminate all price risks.

Interest Rate Risk

At December 31, 2013, we had no variable rate debt outstanding, including on our revolving credit facility. Our revolving credit facility has total borrowing capacity of $1.0 billion, from which we could borrow in the future. To the extent we borrow funds under this facility in any future period, those borrowings would bear interest at LIBOR plus a spread ranging from 1.0% to 1.75% based on our credit ratings and amounts outstanding under the facility.

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Item 8. Financial Statements and Supplementary Data

Management's Annual Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined as a process designed by, or under the supervision of, our principal executive and principal financial officers and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that: (1) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention and timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on our financial statements.

Management believes that the design and operation of our internal control over financial reporting at December 31, 2013 were effective.

We assessed our internal control system using the criteria for effective internal control over financial reporting described in “Internal Control-Integrated Framework” issued by the Committee of Sponsoring Organizations of the Treadway Commission (“1992 COSO” criteria). As of December 31, 2013, based on the results of our assessment, management believed that we had no material weaknesses in internal control over our financial reporting. We maintained effective internal control over financial reporting as of December 31, 2013 based on 1992 COSO criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2013. The report, which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2013, is included herein under the heading “Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting.”

By: /S/ MICHAEL N. MEARS
Chairman of the Board, President, Chief Executive Officer and Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.

By: /S/ JOHN D. CHANDLER
Senior Vice President and Chief Financial Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.

Report of Independent Registered Public Accounting Firm

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

We have audited Magellan Midstream Partners, L.P.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). Magellan Midstream Partners, L.P.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the partnership's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Magellan Midstream Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Magellan Midstream Partners, L.P. as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, owners' equity, and cash flows for each of the three years in the period ended December 31, 2013 and our report dated February 24, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 24, 2014

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Magellan Midstream Partners, L.P. as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, owners' equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of Magellan Midstream Partners, L.P.'s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Magellan Midstream Partners, L.P. at December 31, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Magellan Midstream Partners, L.P.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 24, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Tulsa, Oklahoma
February 24, 2014

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

	Year Ended December 31,		
	2011	2012	2013
Transportation and terminals revenue	$893,369	$970,744	$1,138,328
Product sales revenue	854,528	799,382	744,669
Affiliate management fee revenue	770	1,948	14,609
Total revenue	1,748,667	1,772,074	1,897,606
Costs and expenses:			
Operating	306,415	328,454	346,070
Cost of product sales	706,270	657,108	578,029
Depreciation and amortization	121,179	128,012	142,230
General and administrative	98,669	109,403	132,496
Total costs and expenses	1,232,533	1,222,977	1,198,825
Earnings of non-controlled entities	6,763	2,961	6,275
Operating profit	522,897	552,058	705,056
Interest expense	108,869	117,981	130,463
Interest income	(61)	(107)	(342)
Interest capitalized	(3,174)	(6,195)	(14,339)
Debt placement fee amortization	1,831	2,087	2,424
Income before provision for income taxes	415,432	438,292	586,850
Provision for income taxes	1,866	2,622	4,613
Net income	$413,566	$435,670	$582,237
Allocation of net income (loss):			
Limited partners' interest	$413,629	$435,670	$582,237
Non-controlling owners' interest	(63)	—	—
Net income	$413,566	$435,670	$582,237
Basic net income per limited partner unit	$1.83	$1.92	$2.57
Diluted net income per limited partner unit	$1.83	$1.92	$2.56
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	225,674	226,369	226,829
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	225,974	226,608	227,094

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2011	2012	2013
Net income	$413,566	$435,670	$582,237
Other comprehensive income:			
Derivative activity:			
Net gain (loss) on cash flow hedges[1]	7,739	13,889	(4,744)
Reclassification of net loss (gain) on cash flow hedges to income[1]	(7,903)	(2,924)	4,245
Changes in employee benefit plan assets and benefit obligations recognized in other comprehensive income:			
Net actuarial (loss) gain[2]	(37,058)	(17,804)	14,089
Plan amendment[2]	—	16,020	—
Amortization of actuarial loss[2]	1,591	4,626	5,369
Amortization of prior service credit[2]	(544)	(1,664)	(3,405)
Settlement cost[2]	70	—	—
Total other comprehensive income (loss)	(36,105)	12,143	15,554
Comprehensive income	377,461	447,813	597,791
Comprehensive loss attributable to non-controlling owners' interest in consolidated subsidiaries	(63)	—	—
Comprehensive income attributable to partners' capital	$377,524	$447,813	$597,791

(1) See Note 13–Derivative Financial Instruments for details of the amount of gain/loss recognized in AOCL on derivatives and the amount of gain/loss reclassified from AOCL into income.
(2) See Note 10–Employee Benefit Plans for additional detail of the changes in employee benefit plan assets and benefit obligations that are recognized in other comprehensive income (loss).

See notes to consolidated financial statements.

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

	December 31, 2012	2013
ASSETS		
Current assets:		
Cash and cash equivalents	$328,278	$25,235
Trade accounts receivable (less allowance for doubtful accounts of $5 and $0 at December 31, 2012 and 2013, respectively)	91,114	116,295
Other accounts receivable	12,329	6,462
Inventory	221,888	187,224
Energy commodity derivatives deposits	18,304	14,782
Other current assets	28,365	46,735
Total current assets	700,278	396,733
Property, plant and equipment	4,408,550	4,986,750
Less: accumulated depreciation	943,248	1,070,492
Net property, plant and equipment	3,465,302	3,916,258
Investments in non-controlled entities	107,356	360,852
Long-term receivables	5,135	2,730
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of $16,715 and $8,809 at December 31, 2012 and 2013, respectively)	13,274	7,290
Debt placement costs (less accumulated amortization of $7,886 and $9,113 at December 31, 2012 and 2013, respectively)	15,080	17,505
Tank bottom inventory	58,493	61,915
Other noncurrent assets	1,889	4,269
Total assets	$4,420,067	$4,820,812
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$112,002	$76,326
Accrued payroll and benefits	32,434	42,243
Accrued interest payable	42,059	44,935
Accrued taxes other than income	33,089	38,574
Environmental liabilities	14,442	12,147
Deferred revenue	46,371	63,164
Accrued product purchases	72,049	63,033
Energy commodity derivatives contracts, net	7,338	6,737
Current portion of long-term debt	—	249,971
Other current liabilities	32,836	41,146
Total current liabilities	392,620	638,276
Long-term debt	2,393,408	2,435,316
Long-term pension and benefits	68,134	51,637
Other noncurrent liabilities	16,382	21,802
Environmental liabilities	33,821	26,339
Commitments and contingencies		
Partners' capital:		

Limited partner unitholders (226,201 units and 226,679 units outstanding at December 31, 2012 and 2013, respectively)	1,550,760	1,666,946
Accumulated other comprehensive loss	(35,058)	(19,504)
Total partners' capital	1,515,702	1,647,442
Total liabilities and partners' capital	$4,420,067	$4,820,812

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2011	2012	2013
Operating Activities:			
Net income	$413,566	$435,670	$582,237
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	121,179	128,012	142,230
Debt placement fee amortization	1,831	2,087	2,424
Loss on sale and retirement of assets	8,599	12,625	7,835
Earnings of non-controlled entities	(6,763)	(2,961)	(6,275)
Distributions from investments in non-controlled entities	5,598	2,961	2,494
Equity-based incentive compensation expense	17,710	21,036	24,083
Changes in employee benefit plan assets and benefit obligations	1,117	2,962	1,964
Changes in components of operating assets and liabilities (Note 3)	14,486	42,699	15,708
Net cash provided by operating activities	577,323	645,091	772,700
Investing Activities:			
Property, plant and equipment:			
Additions to property, plant and equipment	(199,665)	(354,168)	(383,757)
Proceeds from sale and disposition of assets	6,299	1,056	3,610
Increase (decrease) in accounts payable related to capital expenditures	2,126	55,133	(37,678)
Acquisition of business	—	—	(192,000)
Acquisition of assets	(17,807)	—	(22,506)
Acquisition of non-controlling owners' interests	(40,500)	—	—
Investments in non-controlled entities	(8,094)	(74,934)	(250,495)
Distributions in excess of earnings of non-controlled entities	—	4,832	780
Other	(1,100)	—	—
Net cash used by investing activities	(258,741)	(368,081)	(882,046)
Financing Activities:			
Distributions paid	(350,892)	(403,485)	(475,461)
Net repayments under revolver	(15,000)	—	—
Borrowings under long-term notes	260,914	248,345	298,680
Debt placement costs	(4,575)	(2,552)	(4,849)
Net receipt from (payment on) interest rate derivatives	5,926	10,977	(184)
Increase (decrease) in outstanding checks	(5,408)	1,364	376
Settlement of tax withholdings on long-term incentive compensation	(7,410)	(13,001)	(12,259)
Net cash used by financing activities	(116,445)	(158,352)	(193,697)
Change in cash and cash equivalents	202,137	118,658	(303,043)
Cash and cash equivalents at beginning of period	7,483	209,620	328,278
Cash and cash equivalents at end of period	$209,620	$328,278	$25,235
Supplemental non-cash financing activities:			
Issuance of MMP limited partner units in settlement of long-term incentive plan awards	$4,315	$7,295	$6,404

See notes to consolidated financial statements.

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

	Partners' Capital			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Non-controlling Owners' Interest	Total Owners' Equity
Balance, January 1, 2011	$1,466,404	$ (11,096)	$14,263	$1,469,571
Comprehensive income:				
Net income (loss)	413,629	—	(63)	413,566
Total other comprehensive loss	—	(36,105)	—	(36,105)
Total comprehensive income (loss)	413,629	(36,105)	(63)	377,461
Distributions	(350,892)	—	—	(350,892)
Equity method incentive compensation expense	11,043	—	—	11,043
Issuance of MMP limited partner units in settlement of long-term incentive plan awards	4,315	—	—	4,315
Settlement of tax withholdings on long-term incentive compensation	(7,410)	—	—	(7,410)
Acquisition of non-controlling owners' interest	(26,300)	—	(14,200)	(40,500)
Other	(185)	—	—	(185)
Balance, December 31, 2011	1,510,604	(47,201)	—	1,463,403
Comprehensive income:				
Net income	435,670	—	—	435,670
Total other comprehensive income	—	12,143	—	12,143
Total comprehensive income	435,670	12,143	—	447,813
Distributions	(403,485)	—	—	(403,485)
Equity method incentive compensation expense	14,118	—	—	14,118
Issuance of MMP limited partner units in settlement of long-term incentive plan awards	7,295	—	—	7,295
Settlement of tax withholdings on long-term incentive compensation	(13,001)	—	—	(13,001)
Other	(441)	—	—	(441)
Balance, December 31, 2012	1,550,760	(35,058)	—	1,515,702
Comprehensive income:				
Net income	582,237	—	—	582,237
Total other comprehensive income	—	15,554	—	15,554
Total comprehensive income	582,237	15,554	—	597,791
Distributions	(475,461)	—	—	(475,461)
Equity method incentive compensation expense	15,532	—	—	15,532
Issuance of MMP limited partner units in settlement of long-term incentive plan awards	6,404	—	—	6,404
Settlement of tax withholdings on long-term incentive compensation	(12,259)	—	—	(12,259)
Other	(267)	—	—	(267)
Balance, December 31, 2013	$1,666,946	$ (19,504)	$—	$1,647,442

See notes to consolidated financial statements.

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

1. Organization and Description of Business

Organization

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

We operate and report in three business segments: refined products, crude oil and marine storage. Our reportable segments offer different products and services and are managed separately because each requires different marketing strategies and business knowledge.

Description of Business

Refined Products. Our refined products segment includes the operations of our refined products pipeline, our independent terminals, our ammonia pipeline as well as our blending and fractionation activities, each of which is briefly described below:

- Our refined products pipeline consists of approximately 9,500 miles of pipeline and 53 terminals that provide transportation, storage and distribution services. Our refined products pipeline covers a 15-state area from the Gulf Coast across the central U.S. The products transported on our pipeline are primarily gasoline, distillates, aviation fuels and liquefied petroleum gases. Product originates on our pipeline from direct connections to refineries, at our terminals and through interconnections with other interstate pipelines for transportation and ultimate distribution to retail gasoline stations, truck stops, railroads, airports and other end users. Our refined products pipeline also generates fees from ancillary services including ethanol and biodiesel loading and unloading, additive injection, custom blending, terminalling, laboratory testing and data services. Our blending activities involve purchasing liquefied petroleum gases and blending them into gasoline, which creates gasoline available for us to sell. Our fractionation activities include two fractionators along our pipeline system that separate transmix, an unusable mixture of various petroleum products, into gasoline and diesel fuel. We generate transmix from the commingling of products between different product batches during the transportation process on our pipelines. We also purchase transmix from third parties;

- Our 27 independent terminals are part of a distribution network located principally throughout the southeastern U.S. We earn revenue at our independent terminals primarily from fees we charge based on the volumes of refined products distributed from these locations and from ancillary services such as additive injections and ethanol blending; and

- Our ammonia pipeline consists of 1,100 miles of pipeline that transports and distributes ammonia from production facilities in Texas and Oklahoma to various distribution points in the Midwest for use as an agricultural fertilizer. We generate revenue principally from volume-based fees for the transportation of ammonia on our pipeline system.

Crude Oil. Our crude oil segment is comprised of approximately 1,100 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 18 million barrels, of which 12 million is used for leased storage. A brief description of these operations is as follows:

- Our Longhorn crude oil pipeline consists of approximately 450 miles of pipeline which originates from Crane, Texas for deliveries to Houston-area refineries and pipelines;

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

- Our Houston-area crude oil distribution system originates at our East Houston, Texas terminal and other points in the Houston area for delivery to nearby refineries and other pipeline systems;

- Our terminal in Cushing, Oklahoma, one of the largest crude oil trading hubs in the U.S., consists of approximately 10 million barrels used for leased storage. This terminal principally serves refiners, marketers and traders. We earn revenue primarily from leasing tanks as well as from throughput fees;

- Our terminal at East Houston, Texas includes approximately one million barrels of crude oil storage used for leased storage and our terminal at Corpus Christi, Texas includes approximately one million barrels of condensate storage used for leased storage; and

- We own approximately 300 miles of pipeline in Kansas and Oklahoma currently used for crude oil service. A majority 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 crude oil segment also includes ownership interests in the following joint ventures:

- a 50% interest in Osage Pipe Line Company LLC (“Osage”), which owns a 135-mile pipeline that transports crude oil from Cushing, Oklahoma to refineries in El Dorado, Kansas;

- a 50% interest in Double Eagle Pipeline LLC (“Double Eagle”), which transports condensate from the Eagle Ford shale formation in South Texas via a 195-mile pipeline to our terminal in Corpus Christi; and

- a 50% interest in BridgeTex Pipeline Company, LLC (“BridgeTex”), which is constructing 450 miles of pipeline and related infrastructure that is being constructed to transport crude oil from Colorado City, Texas for delivery to the Houston and Texas City, Texas refineries. This pipeline is expected to begin service in mid-2014.

Marine Storage. Our marine storage segment is comprised of storage terminals, which store and distribute refined products. Our storage terminals are comprised of five facilities that have marine access in New Haven, Connecticut, Wilmington, Delaware, Marrero, Louisiana, and Corpus Christi and Galena Park, Texas that are located near major refining hubs along the U.S. Gulf and East Coasts. Our marine storage terminals have an aggregate storage capacity of approximately 26 million barrels of wholly-owned storage. Because the rates charged at these terminals are unregulated, the marketplace determines the prices we can charge for our services. We earn revenue through storage and ancillary fees, including product heating, blending, mixing and additive injection for refiners and other large end users of refined products. We have a 50% interest in a refined products storage company, Texas Frontera, LLC ("Texas Frontera"), that owns approximately one million barrels of storage located at our terminal in Galena Park, Texas, which is included in our aggregate storage capacity.

2. Summary of Significant Accounting Policies

Basis of Presentation. Our consolidated financial statements include our refined products, crude oil and marine storage segments. We consolidated all entities in which we have ownership interests, except four 50%-owned investments that we do not control and which we have determined are not variable interest entities. Accordingly, we apply the equity method of accounting for the following entities: (i) Osage; (ii) Texas Frontera; (iii) Double Eagle; and (iv) BridgeTex. We have eliminated all intercompany transactions.

Use of Estimates. The preparation of our consolidated financial statements in conformity with generally accepted accounting principles in the U.S. ("GAAP") requires management to make estimates and assumptions that

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

affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of our consolidated financial statements, as well as their impact on the reported amounts of revenue and expense during the reporting periods. Actual results could differ from those estimates.

Cash Equivalents. Cash and cash equivalents include demand and time deposits and highly marketable securities or funds that own highly marketable securities with original maturities of three months or less when acquired. We periodically assess the financial condition of the institutions where we hold these funds and at December 31, 2012 and 2013, we believed our credit risk relative to these funds was minimal.

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

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

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

We depreciate most of our assets individually on a straight-line basis over their useful lives; however, we group the individual components of certain assets, such as some of our older tanks, together into a composite asset, and we depreciate those assets using a composite rate. We assign asset lives based on reasonable estimates when we place an asset into service. Subsequent events could cause us to change our estimates, which would affect the future calculation of depreciation expense. The range of depreciable lives by asset category is detailed in Note 8—Property, Plant and Equipment.

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

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

Asset Retirement Obligation. We record the fair value of a liability related to the retirement of long-lived assets at the time we incur a legal obligation if the liability can be reasonably estimated. When we initially record the liability, we increase the carrying amount of the related asset by the amount of the liability. Over time, we accrete the liability to its future value and record the accretion amount to operating expense.

Our operating assets generally consist of underground pipelines and related components along rights-of-way and above ground storage tanks and related facilities. Our right-of-way agreements typically do not require the dismantling, removal and reclamation of the right-of-way upon permanent cessation of pipeline service.

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

Additionally, management is unable to predict when, or if, our pipelines, storage tanks and related facilities would become completely obsolete and require decommissioning. Accordingly, except for a $4.2 million liability associated with anticipated tank liner and seal replacements, we have recorded no other liability or corresponding asset as an asset retirement obligation as both the amounts and timing of such potential future costs are indeterminable.

Investments in Non-Controlled Entities. We account for investments greater than 20% in affiliates that we do not control using the equity method of accounting. Under this method, an investment is recorded at our acquisition cost or capital contributions, plus equity in earnings or losses since acquisition or formation, plus interest capitalized, less distributions received and amortization of excess net investment. Excess net investment is the amount by which our initial investment exceeded our proportionate share of the book value of the net assets of the investment. We amortize excess net investment over the weighted-average depreciable asset lives of the equity investee. Our unamortized excess net investment was $15.8 million and $15.1 million at December 31, 2012 and 2013, respectively. We evaluate equity method investments for impairment annually or whenever events or circumstances indicate that there is an other-than-temporary loss in value of the investment. In the event that we determine that the loss in value of an investment is other-than-temporary, we would record a charge to earnings to adjust the carrying value to fair value. We recognized no equity investment impairments during 2011, 2012 or 2013.

Goodwill and Other Intangible Assets. We do not amortize goodwill, which represents the excess of fair value of the business acquired over the fair value of assets acquired and liabilities assumed. We evaluate goodwill for impairment annually and when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. Goodwill was $53.3 million at both December 31, 2012 and 2013. Our reported goodwill at December 31, 2013 included $38.4 million allocated to our refined products segment, $12.1 million allocated to our crude oil segment and $2.8 million allocated to our marine storage segment.

We base our determination of whether goodwill is impaired on management's estimate of the fair value of our reporting units using a discounted future cash flow (“DFCF”) model as compared to their carrying values. Critical assumptions used in our DFCF model included: (i) time horizon of 20 years, (ii) operating margin growth of 2.5%, (iii) annual maintenance capital spending growth of 2.5% and (iv) 11.0 times earnings before interest, taxes and depreciation and amortization ("EBITDA") multiple for terminal value. Management believes an 11.0 times EBITDA multiple is conservative and reasonable for determining terminal value because market participants in the energy industry community use EBITDA multiples ranging from 11.0 to 14.0, and higher, to determine fair value for assets being acquired or sold. We use October 1 as our impairment measurement test date and have determined that our goodwill was not impaired as of October 1, 2011, 2012 or 2013. If impairment were to occur, we would charge the amount of the impairment against earnings in the period in which the impairment occurred. The amount of the impairment would be determined by subtracting the implied fair value of the reporting unit goodwill from the carrying amount of the goodwill.

Judgments and assumptions are inherent in management's estimates used to determine the fair value of our operating segments and are consistent with what management believes would be utilized by the primary market participant. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in our financial statements.

We amortize other intangible assets over their estimated useful lives of 5 years up to 25 years. The weighted-average asset life of our other intangible assets at December 31, 2013 was approximately 7 years. We adjust the useful lives of our other intangible assets if events or circumstances indicate there has been a change in the remaining useful lives. We review our other intangible assets for impairment whenever events or changes in circumstances indicate we should assess the recoverability of the carrying amount of the intangible asset. We recognized no impairments for other intangible assets in 2011, 2012 and 2013. Amortization of other intangible assets was $2.8 million, $1.9 million and $6.0 million in 2011, 2012 and 2013, respectively, of which $0.6 million,

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

$0.6 million and $0.2 million was charged against transportation and terminals revenue in each year during 2011, 2012 and 2013, respectively. During 2013, we retired fully amortized intangible assets of $13.9 million.

Tank Bottom Inventory. A contract we have with a customer at our crude oil terminal in Cushing, Oklahoma requires us to maintain a minimum volume of crude oil in the tanks they utilize at that facility. Because of this contractual requirement, the crude oil we own at that facility is not sold in the normal course of our business; therefore, we classify these crude oil barrels as a long-term asset carried at cost adjusted for gains or losses on certain derivative contracts as described below. At December 31, 2013, our tank bottom inventory consisted of 0.7 million barrels of crude oil with a carrying value of $61.9 million. We have entered into New York Mercantile Exchange ("NYMEX") contracts representing 0.7 million barrels of crude oil, which we have designated as fair value hedges against price changes in our tank bottom inventory. The cumulative losses of these derivative agreements as of December 31, 2012 and 2013 were $5.5 million and $8.9 million, respectively, which were recorded as increases to the tank bottom inventory.

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

Judgments and assumptions are inherent in management's estimate of undiscounted future cash flows used to determine recoverability of an asset and the estimate of an asset's fair value used to calculate the amount of impairment to recognize. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the financial statements.
Impairments we recognized in 2011, 2012 and 2013 were not material.

Debt Placement Costs. We capitalize costs incurred for debt borrowings when paid and amortize those costs over the life of the associated debt instrument using the effective interest method. When debt is retired before its scheduled maturity date, we write off any remaining placement costs associated with that debt.

Interest Capitalized. During construction, we capitalize interest on all construction projects requiring a completion period of three months or longer and total project costs exceeding $0.5 million, based on the weighted-average interest rate of our debt.

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

We develop pension, postretirement medical and life benefits costs from actuarial valuations. We establish actuarial assumptions to anticipate future events and use those assumptions when calculating the expense and liabilities related to these plans. These factors include assumptions management makes concerning interest rates, expected investment return on plan assets, rates of increase in health care costs, turnover rates and rates of future compensation increases, among others. In addition, we use subjective factors such as withdrawal and mortality rates to develop actuarial valuations. Management reviews and updates these assumptions on an annual basis. The actuarial assumptions that we use may differ from actual results due to changing market rates or other factors. These differences could affect the amount of pension and postretirement medical and life benefit expense we have recorded or may record.

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

Paid-Time Off Benefits. We recognize liabilities for paid-time off benefits when earned. Paid-time off liabilities were $12.8 million and $14.3 million at December 31, 2012 and 2013, respectively. These balances represented the remaining vested paid-time off benefits of employees. We reflect liabilities for paid-time off in the accrued payroll and benefits balances of the accompanying consolidated balance sheets.

Derivative Financial Instruments. We record derivative instruments on our balance sheets at fair value as either assets or liabilities. We account for derivatives that qualify for and are elected for treatment as normal purchases and sales using traditional accrual accounting.

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

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

We have entered into NYMEX commodity based futures contracts to hedge against price changes on a portion of the refined products we expect to sell in the future. Some of these contracts have qualified as cash flow or fair value hedges under Accounting Standards Codification ("ASC") No. 815, Derivatives and Hedging, while others have not. We record the effective portion of the gains or losses for those contracts that qualify as cash flow hedges in other comprehensive income and the ineffective portion in product sales revenue. We reclassify gains and losses from contracts that qualify as cash flow hedges from other comprehensive income to product sales revenue when the hedged transaction occurs and we terminate the derivative agreement. We record the effective portion of the gains or losses for those contracts that qualify as fair value hedges as adjustments to the assets or liabilities being hedged and the ineffective portions as adjustments to other income or expense. We recognize the change in fair value of those agreements that are not designated as hedges in product sales revenue, except for those undesignated agreements that economically hedge the inventories associated with our pipeline system overages or forecasted butane purchases. We record the change in fair value of those agreements in operating expenses and cost of product sales, respectively.

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

See Comprehensive Income in this Note 2 for details of the derivative gains and losses included in accumulated other comprehensive loss.

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

Revenue Recognition. We recognize pipeline transportation revenue when shipments are complete. We recognize pipeline transportation revenue for crude oil shipments when our customers take possession of their product from our system. For ammonia shipments and shipments of refined products under published tariffs that combine transportation and terminalling services, shipments are complete when customers take possession of their product from our system through tanker trucks, railcars or third-party pipelines. For all other shipments, where terminalling services are not included in the tariff, shipments are complete when the product arrives at the customer-designated delivery point. We recognize injection service fees associated with customer proprietary additives upon injection to the customer's product, which occurs at the time we deliver the product to our customers. We recognize leased tank storage, pipeline capacity leases, terminalling, throughput, ethanol loading and unloading services, laboratory testing, data services, pipeline operation fees and other miscellaneous service-related revenue upon completion of contract services. We recognize product sales upon delivery of the product to the customer. We increase or decrease, as appropriate, product sales for gains and losses associated with the period change in fair value of our NYMEX agreements that we do not designate as hedges, except for those undesignated agreements that economically hedge the inventories associated with our pipeline system overages (which are recorded as adjustments to operating expense), and for the ineffective portion of our NYMEX agreements that we designate as cash flow hedges. When the physical sale of hedged refined products occurs, we increase or decrease, as appropriate, product sales for the effective portion of the gains and losses of the associated derivative agreement. We record back-to-back purchases and sales of refined products where we are acting as an agent to facilitate refined product sales between a supplier and a customer on a net basis.

Deferred Transportation Revenues and Costs. Generally, we invoice customers on our refined products pipeline for transportation services when their product enters our system. At each period end, we record all invoiced amounts associated with products that have not yet been delivered (in-transit products) as a deferred liability. The value of this liability is calculated as the total of the volume of each product type (for each pipeline region) multiplied by the average tariff rate for that product type for the most recent month invoiced to our customers. We use the most recent month's average tariff rate because the production in our pipeline system generally turns over every month. Additionally, at each period end, we defer the direct costs we have incurred associated with these in-transit products until delivery occurs as a deferred asset. These direct costs are estimated based on our average per-barrel direct delivery cost for the current year multiplied by the total in-transit barrels in our system at the end of the period multiplied by 50% to reflect the average transportation costs incurred for all products across all our pipeline systems. We use 50% of the in-transit barrels because that best represents the average delivery point of all barrels in our pipeline system. These deferred revenues and costs are determined using judgments and assumptions that management considers reasonable.

Pipeline Over/Short Product. The tariffs we charge for our pipeline transportation systems are primarily regulated by the Federal Energy Regulatory Commission (“FERC”); however, certain tariffs are regulated by the Surface Transportation Board or state regulatory authorities. Our tariffs include provisions which allow us to deduct from our customer's inventory a small percentage of the products our customers transport on our pipeline systems. We refer to these product quantities as tender deductions. The purpose of these tender deductions is to help offset the product losses we sustain as a result of shrinkage, evaporation, protection of product quality and product measurement inaccuracies. We record these tender deductions as an increase of pipeline over/short product inventory and a reduction of operating expense. Each period end, we measure the volume of each type of product in our pipeline system which is compared to the volumes of our shippers' inventories (as adjusted for tender deductions). To the extent that the product volumes in our pipeline system exceeds the volumes of our shippers' book inventories, we increase our product inventories and recognize a gain and to the extent the product in our pipeline system is less than our shippers' book inventories, we record a liability (for product owed to our shippers) and recognize a loss. The product gains and losses we recognize are recorded based on period end product market prices and we include those gains or losses in operating expenses on our consolidated statements of income.

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

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

Equity-Based Incentive Compensation Awards. The compensation committee of our general partner (the “compensation committee") has approved incentive awards of phantom units representing limited partner interests in us to certain employees. The awards granted include performance-based awards and retention awards, both of which contain distribution equivalent rights. Further, the compensation committee has issued phantom units with distribution equivalent rights to our independent directors who have deferred the receipt of board fees into the director deferred compensation plan.

Under ASC 718, Compensation-Stock Compensation, we classify unit awards as either equity or liabilities. Fair value for award grants classified as equity is determined on the grant date of the award, and we recognize this value as compensation expense ratably over the requisite service period, which is the vesting period of each unit award. Because all of our unit awards contain full distribution equivalent rights, the per-unit fair value of equity awards is the closing price of our limited partner units on the grant date. Compensation expense for awards classified as equity is calculated as the number of unit awards classified as equity less estimated forfeitures, multiplied by the per unit grant date fair value of those awards, multiplied by the percentage of the requisite service period completed at each period end, multiplied by the expected payout percentage, less previously-recognized compensation expense. We re-measure unit awards classified as liabilities at fair value on the close of business at each reporting period end until settlement date. Fair value at each re-measurement date is the closing price of our limited partner units at each period end. Compensation expense for unit awards classified as liabilities is the number of unit awards classified as liabilities less estimated forfeitures, multiplied by the re-measured per-unit fair value of the awards, multiplied by the percentage of the requisite service period completed at each period end, multiplied by the expected payout percentage, less previously-recognized compensation expense.

Performance-based awards include provisions that can result in payouts to the recipients from 0% up to 250% of the amount of the award. Additionally, certain of these awards are also subject to personal and other performance components, which could increase or decrease the payout of the number of limited partner units by as much as 20%. Judgments and assumptions of the final award payouts are inherent in the accruals recorded for equity-based incentive compensation costs. The use of alternate judgments and assumptions could result in the recognition of different levels of equity-based incentive compensation costs.

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

The vesting period of the performance-based awards is three years. The vesting period for retention awards generally does not exceed three years; however, certain retention awards with a four-year vesting period have been granted. We settle vested non-director award grants by issuing new units, except for the associated tax withholding, which we settle by paying with cash on hand. Phantom units issued to our directors are settled in cash in January of the year following their death or resignation from the board of directors of our general partner.

Contingencies and Environmental. Environmental expenditures are charged to operating expense or capitalized based on the nature of the expenditures. We expense expenditures that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation. We record environmental liabilities assumed in a business combination at fair value, otherwise, we record environmental liabilities on an undiscounted basis. We recognize liabilities for other commitments and contingencies when, after analyzing the available information, we determine it is probable that an asset has been impaired, or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When we can estimate a range of probable loss, we accrue the most likely amount within that range, or if no amount is more likely than another, we accrue the minimum of the range of probable loss. We expense legal costs associated with loss contingencies as incurred.

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

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

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

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

The amounts recognized as provision for income taxes in our results of operations reflects a partnership-level tax levied by the state of Texas. This tax is based on revenues less direct costs of sale for our assets apportioned to the state of Texas.

Net Income Per Unit. We calculate basic net income per limited partner unit for each period by dividing the limited partners' allocation of net income by the weighted-average number of limited partner units outstanding. Diluted net income per limited partner unit for each period is the same calculation as basic net income per limited partner unit, except the weighted-average limited partner units outstanding includes the dilutive effect of phantom unit grants associated with our long-term incentive plan in periods where contingent performance metrics have been met.

Comprehensive Income. We account for comprehensive income in accordance with ASC 220, Comprehensive Income. Comprehensive income was determined based on our net income adjusted for changes in other comprehensive income (loss) from our derivative hedging transactions, related amortization of realized gains/losses and adjustments to record our pension and postretirement benefit obligation liabilities at the funded status of the present value of the benefit obligations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Amounts included in accumulated other comprehensive loss ("AOCL") are as follows (in thousands):

	Derivative Gains (Losses)	Pension and Postretirement Liabilities	Accumulated Other Comprehensive Loss[3]
Balance, January 1, 2011	$3,325	$(14,421)	$(11,096)
Derivative activity:			
Net gain on cash flow hedges[1]	7,739	—	7,739
Reclassification of net gain on cash flow hedges to income[1]	(7,903)	—	(7,903)
Changes in employee benefit plan assets and benefit obligations recognized in other comprehensive income:			
Net actuarial loss[2]	—	(37,058)	(37,058)
Amortization of actuarial loss[2]	—	1,591	1,591
Amortization of prior service credit[2]	—	(544)	(544)
Settlement cost[2]	—	70	70
Balance, December 31, 2011	3,161	(50,362)	(47,201)
Derivative activity:			
Net gain on cash flow hedges[1]	13,889	—	13,889
Reclassification of net gain on cash flow hedges to income[1]	(2,924)	—	(2,924)
Changes in employee benefit plan assets and benefit obligations recognized in other comprehensive income:			
Net actuarial loss[2]	—	(17,804)	(17,804)
Plan amendment[2]	—	16,020	16,020
Amortization of actuarial loss[2]	—	4,626	4,626
Amortization of prior service credit[2]	—	(1,664)	(1,664)
Balance, December 31, 2012	14,126	(49,184)	(35,058)
Derivative activity:			
Net loss on cash flow hedges[1]	(4,744)	—	(4,744)
Reclassification of net loss on cash flow hedges to income[1]	4,245	—	4,245
Changes in employee benefit plan assets and benefit obligations recognized in other comprehensive income:			
Net actuarial gain[2]	—	14,089	14,089
Amortization of actuarial loss[2]	—	5,369	5,369
Amortization of prior service credit[2]	—	(3,405)	(3,405)
Balance, December 31, 2013	$13,627	$(33,131)	$(19,504)

(1) See Note 13–Derivative Financial Instruments for additional detail of the amount of gain (loss) recognized in AOCL on derivatives and the amount of (gain) loss reclassified from AOCL into income.
(2) See Note 10–Employee Benefit Plans for additional detail of the changes in employee benefit plan assets and benefit obligations that are recognized in other comprehensive income (loss).

(3) Includes amounts allocated to the non-controlling owners' interest.

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New Accounting Pronouncements

In February 2013, the Financial Accounting Standards Board ("FASB") issued ASU 2013-02, Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. The amendments in ASU 2013-02 do not change the current requirements for reporting net income or other comprehensive income in financial statements. However, the amendments require an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. ASU 2013-02 became effective for annual and interim periods beginning after December 15, 2012 and was to be applied prospectively. Our adoption of this standard in the first quarter of 2013 did not have a material impact on our results of operations, financial position or cash flows.

In December 2011, the FASB issued ASU 2011-11, Disclosures about Offsetting Assets and Liabilities. This ASU requires entities that have financial instruments and derivatives that are either: (i) offset in accordance with ASC Topic 210 or Topic 815 or (ii) are subject to an enforceable master netting arrangement or similar agreement to make additional disclosures of the gross and net amounts of those assets and liabilities, the amounts offset in accordance with ASC Topics 210 and 815, as well as qualitative disclosures of the entity's master netting arrangement or similar agreement. In January 2013, the FASB issued ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. The amendments in ASU 2013-01 clarify that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with ASC Topic 815, Derivatives and Hedging. ASU 2011-11 must be applied retrospectively and became effective for fiscal years beginning on or after January 1, 2013. We adopted these standards in the first quarter of 2013 and their adoption did not have a material impact on our results of operations, financial position or cash flows.

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

3. Consolidated Statements of Cash Flows

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

	Year Ended December 31,		
	2011	2012	2013
Restricted cash	$14,379	$—	$—
Trade accounts receivable and other accounts receivable	5,791	(10,867)	(19,314)
Inventory	(42,452)	36,972	34,664
Energy commodity derivatives contracts, net of derivatives deposits	(19,782)	16,097	534
Accounts payable	20,226	(11,175)	2,002
Accrued payroll and benefits	(2,209)	2,250	9,809
Accrued interest payable	4,069	1,512	2,876
Accrued taxes other than income	617	5,519	5,485
Accrued product purchases	12,476	12,249	(9,016)
Deferred revenue	5,250	6,388	16,793
Current and noncurrent environmental liabilities	16,861	(1,372)	(12,247)
Other current and noncurrent assets and liabilities	(740)	(14,874)	(15,878)
Total	$14,486	$42,699	$15,708

At December 31, 2011, 2012 and 2013, the long-term pension and benefits liability was increased (decreased) by $37.1 million, $1.8 million and $(14.1) million, respectively, resulting in a corresponding increase (decrease) in accumulated other comprehensive loss. These non-cash amounts were reflected in the consolidated financial statements but were not reflected in the statements of cash flows.

4. Investments in Non-Controlled Entities

Texas Frontera. We own a 50% interest in Texas Frontera, which owns approximately one million barrels of refined products storage at our Galena Park, Texas terminal. The storage capacity owned by this venture is leased to an affiliate of Texas Frontera under a long-term lease agreement. Texas Frontera began operations in October 2012. We receive management fees from Texas Frontera, which we report as affiliate management fee revenue on our consolidated statements of income.

Osage. We own a 50% interest in Osage, which owns a 135-mile crude oil pipeline in Oklahoma and Kansas that we operate. We receive management fees from Osage, which we report as affiliate management fee revenue on our consolidated statements of income.

Double Eagle. We own a 50% interest in Double Eagle, which transports condensate from the Eagle Ford shale formation in South Texas via a 195-mile pipeline to our terminal in Corpus Christi, Texas. Double Eagle is operated by an affiliate of the other 50% member of Double Eagle. We receive connection fees from Double Eagle that are included in our transportation and terminals revenue on our consolidated statements of income. For the year ended December 31, 2013, we received connection fees of $1.4 million and recognized a $0.2 million trade accounts receivable from Double Eagle at December 31, 2013.

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BridgeTex. We own a 50% interest in BridgeTex, which is in the process of constructing a 450-mile pipeline with related infrastructure to transport crude oil from Colorado City, Texas for delivery to Houston and Texas City, Texas refineries. This pipeline is expected to begin service in mid-2014. We receive construction management fees from BridgeTex, which we report as affiliate management fee revenue on our consolidated statements of income.

During 2013, we received $4.8 million from BridgeTex as a deposit for the purchase of emission reduction credits, which we expect to transfer to BridgeTex during the first half of 2014. Also in 2013, we received $1.4 million from BridgeTex for the purchase of easement rights from us, of which $0.7 million was recorded as a reduction of operating expense and $0.7 million was recorded as an adjustment to our investment in BridgeTex, which will be amortized as a reduction of operating expense over the weighted average depreciable lives of the BridgeTex assets.

A summary of our investments in non-controlled entities follows (in thousands):

	Texas Frontera	Osage	Double Eagle	BridgeTex	Consolidated
Investment at December 31, 2012	$15,728	$18,888	$40,840	$31,900	$107,356
Additional investment	—	—	35,500	214,995	250,495
Earnings (losses) of non-controlled entities:					
Proportionate share of earnings (losses)	2,494	4,383	82	(20)	6,939
Amortization of excess investment	—	(664)	—	—	(664)
Earnings (losses) of non-controlled entities	2,494	3,719	82	(20)	6,275
Less:					
Distributions of earnings from investments in non-controlled entities	2,494	—	—	—	2,494
Distributions in excess of earnings of non-controlled entities	780	—	—	—	780
Investment at December 31, 2013	$14,948	$22,607	$76,422	$246,875	$360,852

The operating results from Texas Frontera are included in our marine storage segment and the operating results from Osage, Double Eagle and BridgeTex are included in our crude oil segment.

Our initial investment in Osage included an excess net investment amount of $21.7 million. Excess investment is the amount by which our initial investment exceeded our proportionate share of the book value of the net assets of the investment. The unamortized excess net investment amount at December 31, 2013 was $15.1 million.

5. Business Combinations

During 2013, we acquired certain refined petroleum products pipelines and terminals from Plains All American Pipeline, L.P. We have accounted for this acquisition as a business combination under the acquisition method of accounting in accordance with ASC 805, Business Combinations. The acquisition was completed in two parts, as follows:

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

- New Mexico/Texas System. In July 2013, we acquired a 250-mile pipeline that transports refined petroleum products from El Paso, Texas north to Albuquerque, New Mexico and transports products south to the U.S.–Mexico border for delivery within Mexico via a third-party pipeline for $57.0 million, which we funded with cash on hand. This pipeline system serves as a natural extension of our existing refined products pipeline system and allows us to provide options to customers in Albuquerque and central New Mexico to access refined products from West Texas, Gulf Coast and Mid-Continent refiners. The operating results have been included in our refined products segment since the acquisition date.

- Rocky Mountain System. In November 2013, we acquired approximately 550 miles of common carrier pipeline that distributes refined petroleum products in Colorado, South Dakota and Wyoming. The system includes four terminals with nearly 1.7 million barrels of storage. We funded this $135.0 million acquisition primarily with proceeds from our debt offering in October 2013. This pipeline system is a strategic fit with our existing assets and customer relationships and extends the reach of our pipeline system to allow us to serve new geographic markets. The operating results have been included in our refined products segment since the acquisition date.

We have completed our appraisal of the assets acquired with the New Mexico/Texas pipeline system and the fair values and purchase price allocations for these assets are final; however, we are still in the process of completing an appraisal of the Rocky Mountain system assets acquired in November 2013. Our final determination of the fair value of these assets and the allocation of the purchase price will be made when that valuation process has been completed. The purchase price and initial assessment of the fair value of the assets acquired and liabilities assumed in the business combination we completed during 2013 were as follows (in thousands):

Purchase price allocation:	$192,000
Fair value of assets acquired (liabilities assumed):	
Property, plant and equipment	$192,422
Other current assets	2,048
Current environmental liabilities	(2,470)
Total	$192,000

The following amounts from our business combination were included in our operating results since the date of acquisition through December 31, 2013 (in thousands):

Revenue	$12,661
Operating profit	$6,400

The following summarized pro forma consolidated income statement information assumes that the acquisition of a business during 2013 referred to above occurred as of January 1, 2012. These pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had this acquisition been completed on January 1, 2012 or the results that will be attained in the future (in thousands).

	Year Ended December 31, 2012		Year Ended December 31, 2013	
	As Reported	Pro-Forma	As Reported	Pro-Forma
Revenue	$1,772,074	$1,812,635	$1,897,606	$1,924,316
Net income	$435,670	$442,096	$582,237	$591,377

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Significant pro forma adjustments include historical results of the acquired assets and our calculation of G&A expense, depreciation expense and interest expense on borrowings necessary to finance this acquisition. Acquisition and start-up costs related to the assets acquired totaling $2.8 million were recorded to operating expenses during 2013. These costs were reclassified from 2013 to 2012, as the acquisition was assumed to have been completed January 1, 2012 for this presentation.

6. Inventory

Inventory at December 31, 2012 and 2013 was as follows (in thousands):

	2012	2013
Refined petroleum products	$88,630	$77,144
Liquefied petroleum gases	45,657	23,476
Transmix	63,026	72,156
Crude oil	17,443	7,188
Additives	7,132	7,260
Total inventory	$221,888	$187,224

7. Product Sales Revenue

The amounts reported as product sales revenue on our consolidated statements of income include revenue from the physical sale of petroleum products and from mark-to-market adjustments from NYMEX contracts. We use NYMEX contracts to hedge against changes in the price of refined products we expect to sell from our business activities where we acquire or produce petroleum products. Some of these NYMEX contracts qualify for hedge accounting treatment and we designate and account for these as either cash flow or fair value hedges. The effective portion of the fair value changes in contracts designated as cash flow hedges are recognized as adjustments to product sales when the hedged product is physically sold. Ineffectiveness in the contracts designated as cash flow hedges is recognized as an adjustment to product sales in the period the ineffectiveness occurs. We account for NYMEX contracts that do not qualify for hedge accounting treatment as economic hedges, with the period changes in fair value recognized as product sales, except for those agreements that economically hedge the inventories associated with our pipeline system overages (the period changes in the fair value of these agreements are charged to operating expense). See Note 13 - Derivative Financial Instruments for further disclosures regarding our NYMEX contracts.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

For the years ended December 31, 2011, 2012 and 2013, product sales revenue included the following (in thousands):

	Year Ended December 31,		
	2011	2012	2013
Physical sale of refined products	$870,007	$833,581	$755,266
NYMEX contract adjustments:			
Change in value of NYMEX contracts that did not qualify for hedge accounting treatment and the effective portion of gains and losses of matured NYMEX contracts that qualified for hedge accounting treatment associated with our butane blending and fractionation activities[1]	(4,330)	(30,270)	(10,586)
Change in value of NYMEX contracts that did not qualify for hedge accounting treatment associated with the Houston-to-El Paso pipeline section linefill working inventory[1]	(11,149)	(3,940)	—
Other	—	11	(11)
Total NYMEX contract adjustments	(15,479)	(34,199)	(10,597)
Total product sales revenue	$854,528	$799,382	$744,669

(1) The associated refined products for these activities are, to the extent still owned as of the statement date, or were, to the extent no longer owned as of the statement date, classified as inventory in current assets on our consolidated balance sheets.

8. Property, Plant and Equipment

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

	December 31,		Estimated Depreciable
	2012	2013	Lives
Construction work-in-progress	$247,571	$165,129	
Land and rights-of-way	83,014	78,405	
Carrier property	1,835,265	2,135,905	7 to 59 years
Buildings	37,672	41,383	20 to 55 years
Storage tanks	975,277	1,141,271	10 to 40 years
Pipeline and station equipment	479,531	593,396	3 to 59 years
Processing equipment	645,140	716,103	3 to 56 years
Other	105,080	115,158	3 to 48 years
Property, Plant and Equipment, Gross	$4,408,550	$4,986,750	

Carrier property is defined as pipeline assets regulated by the FERC. Other includes total interest capitalized as of December 31, 2012 and 2013 of $24.3 million and $33.2 million, respectively. Depreciation expense for the years ended December 31, 2011, 2012 and 2013 was $118.9 million, $126.7 million and $136.4 million, respectively.

9. Major Customers and Concentration of Risks

Major Customers. No customer accounted for 10% or more of our consolidated total revenue in 2013. However, one customer accounted for 21% and 14% of our consolidated total revenue in 2011 and 2012,

MAGELLAN MIDSTREAM PARTNERS, L.P.
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respectively. The majority of revenue from this customer resulted from sale of refined products that were generated in connection with our butane blending and fractionation activities and from sales associated with the management of our linefill for the Houston-to-El Paso pipeline section, all of which are or were activities conducted by our refined products segment.

Concentration of Risks. We transport, store and distribute refined products for refiners, marketers, traders and end users of those products. We derive the major concentration of our revenue from activities conducted in the central U.S. We generally secure transportation and storage revenue with warehouseman's liens. We periodically evaluate the financial condition and creditworthiness of our customers and require additional security as we deem necessary.

As of December 31, 2013, we had 1,459 employees. At December 31, 2013, the labor force of 842 employees assigned to our refined products segment was concentrated in the central U.S. Approximately 26% of these employees were represented by the United Steel Workers (“USW”) and covered by a collective bargaining agreement that expires January 31, 2015. At December 31, 2013, the labor force of 51 employees assigned to our crude oil segment was 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, 2013 was primarily located in the Gulf and East Coast regions of the U.S. Approximately 16% of these employees were represented by the International Union of Operating Engineers (“IUOE”) and covered by a collective bargaining agreement that expires October 31, 2016.

10. Employee Benefit Plans

We sponsor two union pension plans that cover certain union employees (“USW plan” and “IUOE plan,” collectively, the "Union plans") and a pension plan for all non-union employees (“Salaried plan”), a postretirement benefit plan for certain employees and a defined contribution plan.

The annual measurement date of these plans is December 31. The following table presents the changes in benefit obligations and plan assets for pension benefits and other postretirement benefits for the years ended December 31, 2012 and 2013 (in thousands):

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

	Pension Benefits		Other Postretirement Benefits	
	2012	2013	2012	2013
Change in benefit obligation:				
Benefit obligation at beginning of year	$113,914	$142,703	$23,786	$13,195
Service cost	12,222	13,901	396	288
Interest cost	4,862	5,368	821	412
Plan participants' contributions	—	—	221	248
Actuarial loss (gain)	15,975	(14,121)	4,751	(2,675)
Benefits paid	(4,270)	(5,541)	(760)	(1,050)
Plan amendment	—	—	(16,020)	—
Benefit obligation at end of year	142,703	142,310	13,195	10,418
Change in plan assets:				
Fair value of plan assets at beginning of year	70,052	87,106	—	—
Employer contributions	13,336	15,470	539	802
Plan participants' contributions	—	—	221	248
Actual return on plan assets	7,988	3,521	—	—
Benefits paid	(4,270)	(5,541)	(760)	(1,050)
Fair value of plan assets at end of year	87,106	100,556	—	—
Funded status at end of year	$(55,597)	$(41,754)	$(13,195)	$(10,418)
Accumulated benefit obligation	$101,233	$103,466		

The amounts included in pension benefits in the previous table combine the Union plans with the Salaried plan. At December 31, 2012, the fair value of each of the pension plans' assets was less than the fair values of the respective accumulated benefit obligations. At December 31, 2013, the Union plans' assets had a combined accumulated benefit obligation of $41.1 million, which exceeded the combined fair value of plan assets of $36.6 million.

The 2012 actuarial loss of $16.0 million for our pension plans was due primarily to the impact of decreases in the discount rate used to calculate the benefit obligation. The 2013 actuarial gain of $14.1 million was due primarily to the impact of increases in the discount rate used to calculate the benefit obligation.

Prior to July 1, 2012, our postretirement benefits provided coverage to participants age 65 and older that was secondary to Medicare Part A, Part B and Part D. The cost to plan participants for the age-65-and-older component of this coverage was higher than similar medical insurance coverage available in the marketplace. Therefore, in June 2012, we amended our other postretirement medical benefit to exclude coverage for post-65 participants. For participants under age 65, the medical coverage remains unchanged. We accounted for this change as a negative plan amendment which resulted in a reduction of our postretirement liability of $16.0 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

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

	Pension Benefits		Other Postretirement Benefits	
	2012	2013	2012	2013
Amounts recognized in consolidated balance sheet:				
Current accrued benefit cost	$—	$—	$(658)	$(535)
Long-term pension and benefit cost	(55,597)	(41,754)	(12,537)	(9,883)
	(55,597)	(41,754)	(13,195)	(10,418)
Accumulated other comprehensive loss:				
Net actuarial loss	51,899	36,151	11,418	7,708
Prior service cost (credit)	340	33	(14,473)	(10,761)
	52,239	36,184	(3,055)	(3,053)
Net amount recognized in consolidated balance sheet	$(3,358)	$(5,570)	$(16,250)	$(13,471)

Net periodic benefit expense for the years ended December 31, 2011, 2012 and 2013 were as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2011	2012	2013	2011	2012	2013
Components of net periodic pension and postretirement benefit expense:						
Service cost	$9,628	$12,222	$13,901	$430	$396	$288
Interest cost	4,343	4,862	5,368	999	821	412
Expected return on plan assets	(4,357)	(5,066)	(6,228)	—	—	—
Amortization of prior service cost (credit)	307	307	307	(851)	(1,971)	(3,712)
Amortization of actuarial loss	1,424	3,605	4,334	167	1,021	1,035
Settlement cost	70	—	—	—	—	—
Net periodic expense (credit)	$11,415	$15,930	$17,682	$745	$267	$(1,977)

Other changes in plan assets and benefit obligations recognized in other comprehensive loss during 2012 and 2013 were as follows (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2012	2013	2012	2013
Other changes in plan assets and benefit obligations recognized in other comprehensive loss:				
Net actuarial loss (gain)	$13,053	$(11,414)	$4,751	$(2,675)
Plan amendment	—	—	(16,020)	—
Amortization of actuarial loss	(3,605)	(4,334)	(1,021)	(1,035)
Amortization of prior service credit (cost)	(307)	(307)	1,971	3,712
Total recognized in other comprehensive loss	9,141	(16,055)	(10,319)	2
Net periodic expense (credit)	15,930	17,682	267	(1,977)

Total recognized in net periodic benefit cost and other comprehensive loss	$25,071	$1,627	$(10,052)	$(1,975)

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We match our employees' qualifying contributions to our defined contribution plan, resulting in expense to us. Expenses related to the defined contribution plan were $6.2 million, $6.5 million and $7.1 million in 2011, 2012 and 2013, respectively.

The estimated net actuarial loss and prior service cost for the defined benefit pension plans that will be amortized from AOCL into net periodic benefit cost in 2014 are $2.5 million and less than $0.1 million, respectively. The estimated net actuarial loss and prior service credit for the other defined benefit postretirement plan that will be amortized from AOCL into net periodic benefit cost in 2014 are $0.8 million and $(3.7) million, respectively.

The weighted-average rate assumptions used to determine benefit obligations as of December 31, 2012 and 2013 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2012	2013	2012	2013
Discount rate—Salaried plan	4.00%	4.89%	n/a	n/a
Discount rate—USW plan	3.39%	4.26%	n/a	n/a
Discount rate—IUOE plan	3.99%	4.89%	n/a	n/a
Discount rate—Other Postretirement Benefits	n/a	n/a	3.58%	4.52%
Rate of compensation increase—Salaried plan	5.00%	5.00%	n/a	n/a
Rate of compensation increase—USW plan	3.50%	3.50%	n/a	n/a
Rate of compensation increase—IUOE plan	5.00%	5.00%	n/a	n/a

The weighted-average rate assumptions used to determine net pension and other postretirement benefit expense for the years ended December 31, 2011, 2012 and 2013 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2011	2012	2013	2011	2012	2013
Discount rate—Salaried plan	5.54%	4.39%	4.00%	n/a	n/a	n/a
Discount rate—USW plan	5.07%	4.00%	3.39%	n/a	n/a	n/a
Discount rate—IUOE plan	5.52%	4.37%	3.99%	n/a	n/a	n/a
Discount rate—Other Postretirement Benefits	n/a	n/a	n/a	5.56%	3.75 %	3.58 %
Rate of compensation increase—Salaried plan	5.00%	5.00%	5.00%	n/a	n/a	n/a
Rate of compensation increase—USW plan	4.50%	3.50%	3.50%	n/a	n/a	n/a
Rate of compensation increase—IUOE plan	5.00%	5.00%	5.00%	n/a	n/a	n/a
Expected rate of return on plan assets—Salaried plan	6.80%	6.80%	6.80%	n/a	n/a	n/a
Expected rate of return on plan assets—USW plan	6.80%	6.80%	6.80%	n/a	n/a	n/a
Expected rate of return on plan assets—IUOE plan	3.25%	6.80%	6.80%	n/a	n/a	n/a

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The annual assumed rate of increase in the health care cost trend rate for 2014 is 6.0% decreasing systematically to 4.7% by 2087 for pre-65 year-old participants. The health care cost trend rate assumption has a significant effect on the amounts reported. As of December 31, 2013, a 1.0% change in assumed health care cost trend rates would have the following effect (in thousands):

	1% Increase	1% Decrease
Change in total of service and interest cost components	$39	$35
Change in postretirement benefit obligation	$533	$486

The fair value of the pension plan assets at December 31, 2012 were as follows (in thousands):

Asset Category	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Equity Securities[(a)]:				
Small-cap fund	$1,726	$1,726	$—	$—
Mid-cap fund	1,708	1,708	—	—
Large-cap fund	12,810	12,810	—	—
International equity fund	8,019	8,019	—	—
Fixed Income Securities[(a)]:				
Short-term bond funds	2,824	2,824	—	—
Intermediate-term bond funds	16,677	16,677	—	—
Long-term investment grade bond fund	40,370	40,370	—	—
Other:				
Short-term investment fund	2,614	2,614	—	—
Group annuity contract	358	—	—	358
Fair value of plan assets	$87,106	$86,748	$—	$358

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The fair value of the pension plan assets at December 31, 2013 were as follows (in thousands):

Asset Category	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Equity Securities[a]:				
Small-cap fund	$2,480	$2,480	$—	$—
Mid-cap fund	2,465	2,465	—	—
Large-cap fund	18,642	18,642	—	—
International equity fund	11,793	11,793	—	—
Fixed Income Securities[a]:				
Short-term bond funds	3,243	3,243	—	—
Intermediate-term bond funds	12,492	12,492	—	—
Long-term investment grade bond funds	45,900	45,900	—	—
Other:				
Short-term investment funds	3,244	3,244	—	—
Group annuity contract	297	—	—	297
Fair value of plan assets	$100,556	$100,259	$—	$297

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

The group annuity contract is valued at contract value, which approximates fair value as determined by the contract provider. The balance at the end of the year represents total contributions plus interest earned less benefit payments and expenses paid. The group annuity contract is guaranteed a specified return, by the Metropolitan Life Insurance Company, based on the Barclay's Capital Aggregate Bond Fund return. The fair value measurements for the group annuity contract which used significant unobservable inputs (Level 3) for the years ended December 31, 2012 and 2013 were as follows (in thousands):

	2012	2013
Beginning balance	$400	$358
Actual return on plan assets:		
Relating to assets still held at the reporting date	16	(7)
Purchases, issuances, sales and settlements:		
Settlements	(58)	(54)
Ending balance	$358	$297

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

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

Asset Category	Fund’s Investment Strategy
Domestic Equity Securities:	
Small-cap fund	Seeks to track performance of the Center for Research in Security Prices ("CRSP") US Small Cap Index
Mid-cap fund	Seeks to track performance of the CRSP US Mid Cap Index
Large-cap fund	Seeks to track performance of the Standard & Poor’s 500 Index
International equity fund	Seeks long-term growth of capital by investing 65% or more of assets in international equities
Fixed Income Securities:	
Short-term bond funds	Seek current income with limited price volatility through investment in primarily high quality bonds
Intermediate-term bond funds	Seek moderate and sustainable level of current income by investing primarily in high quality fixed income securities with maturities from five to ten years
Long-term investment grade bond funds	Seek high and sustainable current income through investment primarily in long-term high grade bonds
Other:	
Short-term investment funds	Invest primarily in high quality commercial paper and government securities
Group annuity contract	Guarantees a specified return based on a specified index

The expected long-term rate of return on plan assets was determined by combining a review of projected returns, historical returns of portfolios with assets similar to the current portfolios of the union and non-union pension plans and target weightings of each asset classification. Our investment objective for the assets within the pension plans is to earn a return that meets or exceeds the growth of its obligations that result from interest and changes in the discount rate, while avoiding excessive risk. Defined diversification goals are set in order to reduce the risk of wide swings in the market value from year to year, or of incurring large losses that may result from concentrated positions. As a result, our plan assets have no significant concentrations of credit risk. Additionally, liquidity risks are minimized because all of the funds that the plans have invested in are publicly traded. We evaluate risks based on the potential impact of the predictability of contribution requirements, probability of under-funding, expected risk-adjusted returns and investment return volatility. Funds are invested with multiple investment managers. Our segment liabilities are calculated using rates defined by the Pension Protection Act of 2006. Investments are made so as to match the durations of the short and intermediate term liabilities. Additional investments are made to bring the overall investment allocation to 70% debt securities and 30% equity securities. The target allocation and actual weighted-average asset allocation percentages at December 31, 2012 and 2013 were as follows:

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	2012 Actual[(a)]	Target	2013 Actual[(a)]	Target
Equity securities	28%	30%	35%	30%
Debt securities	69%	67%	62%	67%
Other	3%	3%	3%	3%

(a) Cash contributions of $13.3 million and $15.5 million were made to the pension plans during 2012 and 2013, respectively. Amounts contributed in 2012 and 2013 in excess of benefit payments made were to be invested in debt and equity securities over a twelve-month period, with the amounts that remained uninvested as of December 31, 2012 and 2013 scheduled for investment in accordance with the target. Excluding these uninvested cash amounts, the actual allocation percentages at December 31, 2012 would have been 29% equity securities and 71% debt securities and at December 31, 2013, would have been 36% equity securities and 64% debt securities. In 2014, we will invest these uninvested cash amounts to bring the total asset allocation in line with the target allocation.

As of December 31, 2013, the benefit amounts we expect to pay through December 31, 2023 were as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2014	$5,207	$535
2015	$5,507	$590
2016	$6,282	$578
2017	$9,267	$627
2018	$9,032	$665
2019 through 2023	$58,108	$4,205

Contributions estimated to be paid into the plans in 2014 are $19.8 million and $0.5 million for the pension and other postretirement benefit plans, respectively.

11. Related Party Transactions

Barry R. Pearl is an independent member of our general partner's board of directors and is also a director of Targa Resources Partners, L.P. ("Targa"). In the normal course of business, we purchase butane from subsidiaries of Targa. For the years ended December 31, 2011, 2012 and 2013, we made purchases of butane from subsidiaries of Targa of $11.7 million, $27.4 million and $30.4 million, respectively. These purchases were made on the same terms as comparable third-party transactions. The amount payable to Targa at December 31, 2012 was $0.1 million. There were no amounts payable to Targa at December 31, 2013.

In January 2011, our former chief executive officer, Don R. Wellendorf, retired. In conjunction with Mr. Wellendorf's retirement, our general partner's board of directors engaged Mr. Wellendorf as a consultant to us for a period of twelve months beginning in February 2011 for consideration of $0.3 million and an agreement that certain of his previously-awarded phantom unit awards would not be forfeited. Expense associated with these awards for the years ended December 31, 2011 and 2012 was $2.1 million and $0.5 million, respectively.

See Note 4 – Investments in Non-Controlled Entities for a discussion of affiliate joint venture transactions we account for under the equity method.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

12. Debt

Debt at December 31, 2012 and 2013 was as follows (in thousands):

	December 31,		Weighted-Average Interest Rate at December 31, 2013 (a)
	2012	2013	
Revolving credit facility	$—	$—	—%
$250.0 million of 6.45% Notes due 2014	249,905	249,971	6.3%
$250.0 million of 5.65% Notes due 2016	251,609	251,183	5.7%
$250.0 million of 6.40% Notes due 2018	261,411	259,346	5.4%
$550.0 million of 6.55% Notes due 2019	575,065	571,515	5.7%
$550.0 million of 4.25% Notes due 2021	558,088	557,213	4.0%
$250.0 million of 6.40% Notes due 2037	248,981	248,998	6.4%
$250.0 million of 4.20% Notes due 2042	248,349	248,377	4.2%
$300.0 million of 5.15% Notes due 2043	—	298,684	5.2%
Total debt	$2,393,408	$2,685,287	5.2%

(a) Weighted-average interest rate includes the amortization/accretion of discounts and premiums and the amortization/accretion of gains and losses realized on historical cash flow and fair value hedges on interest expense.

The revolving credit facility and notes detailed in the table above are senior indebtedness.

The face value of our debt at December 31, 2012 and 2013 was $2.4 billion and $2.7 billion, respectively. The difference between the face value and carrying value of the debt outstanding is the unamortized portion of terminated fair value hedges and the unamortized discounts and premiums on debt issuances. Realized gains and losses on fair value hedges and note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of those notes. At December 31, 2013, maturities of our debt were as follows: $250.0 million in 2014; $0 in 2015; $250.0 million in 2016; $0 in 2017; $250.0 million in 2018; and $1.9 billion thereafter.

2013 Debt Offering

In October 2013, we issued $300.0 million of 5.15% notes due October 15, 2043 in an underwritten public offering. The notes were issued for the discounted price of 99.6% of par. We used the net proceeds from this offering of approximately $295.6 million, after underwriting discounts and offering expenses of $3.1 million, to repay borrowings outstanding under our revolving credit facility and for general partnership purposes, including expansion capital.

Other Debt

Revolving Credit Facility. During November 2013, we amended our revolving credit facility to increase the borrowing capacity from $800.0 million to $1.0 billion and extend the maturity date from October 2016 to November 2018. In connection with this amendment, we paid $1.7 million of debt placement fees and wrote off $0.2 million of unamortized debt placement fees associated with the original revolving credit facility. Borrowings under our revolving credit facility are unsecured and bear interest at LIBOR plus a spread ranging from 1.0% to 1.75% based on our credit ratings. At December 31, 2013, our borrowing rate under the facility was LIBOR plus 1.125%. Additionally, an unused commitment fee is assessed at a rate from 0.10% to 0.28%, depending on our credit ratings, which was 0.125% at December 31, 2013. Borrowings under this facility may be used for general purposes, including capital expenditures. As of December 31, 2013, there were no borrowings outstanding under this facility with $5.6 million obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets, but decrease our borrowing capacity under the facility.

The revolving credit facility described above requires us to maintain a specified ratio of consolidated debt to EBITDA (as defined in the credit agreement) of no greater than 5.0 to 1.0. In addition, the revolving credit facility and the indentures under which our senior notes were issued contain covenants that limit our ability to, among other things, incur indebtedness secured by certain liens or encumber our assets, engage in certain sale-leaseback transactions and consolidate, merge or dispose of all or substantially all of our assets. We were in compliance with these covenants as of and during the year ended December 31, 2013.

During the years ending December 31, 2011, 2012 and 2013, total cash payments for interest on all indebtedness, excluding the impact of related interest rate swap agreements, were $111.7 million, $123.3 million and $134.6 million, respectively.

13. Derivative Financial Instruments

Interest Rate Derivatives

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

Interest Rate Derivatives Activity During 2013. In September 2013, we entered into $150.0 million of Treasury lock contracts to hedge against the risk of variability of future interest payments on a portion of the debt we issued in early October 2013. We accounted for these contracts as cash flow hedges. These contracts were settled on October 3, 2013 for a loss of $0.2 million. The loss was recorded to other comprehensive income and will be recognized into earnings as an adjustment to our periodic interest accruals over the next 30 years to coincide with interest payments on the underlying debt.

Interest Rate Derivatives Activity During 2012. During 2012, we entered into a total of $250.0 million of forward-starting interest rate swap agreements to hedge against the variability of future interest payments on debt that we anticipated issuing to refinance our $250.0 million of 6.45% notes due June 1, 2014. These forward-starting interest rate swap agreements were accounted for as cash flow hedges. In November 2012, we terminated and settled these agreements and realized a gain of $11.0 million. The gain was recorded to other comprehensive income and will be recognized into earnings as an adjustment to our periodic interest accruals for the 30 years of hedged interest payments following the expected debt issuance. If management were to determine that it was probable this forecasted transaction would not occur in 2014, the $11.0 million gain we have recorded to other comprehensive income would be reclassified into earnings.

Interest Rate Derivatives Activity During 2011. During 2011, we entered into $100.0 million of interest rate swap agreements, which were accounted for as fair value hedges, to hedge against changes in the fair value of a portion of our $250.0 million of 6.40% notes due 2018. In third quarter 2011, we terminated and settled these interest rate swap agreements and received $5.9 million, which was recorded as an adjustment to long-term debt that is being amortized over the remaining life of the notes into interest expense.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Commodity Derivatives

Hedging Strategies

Our butane blending activities produce gasoline products, and we can reasonably estimate the timing and quantities of sales of these products. We use a combination of forward purchase and sale contracts, NYMEX contracts and butane futures agreements to help manage price changes, which has the effect of locking in most of the product margin realized from our butane blending activities that we choose to hedge.

We account for the forward physical purchase and sale contracts we use in our butane blending and fractionation activities as normal purchases and sales. Forward contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting. As of December 31, 2013, we had commitments under these forward purchase and sale contracts as follows (in millions):

	Notional Value	Barrels
Forward purchase contracts	$122.8	2.0
Forward sale contracts	$64.2	0.6

We use NYMEX contracts to hedge against changes in the price of refined products we expect to sell in future periods. Our NYMEX contracts fall into one of three hedge types:

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

Period changes in the fair value of NYMEX agreements that are considered economic hedges, the effective portion of changes in the fair value of cash flow hedges that are reclassified from accumulated other comprehensive income/loss and any ineffectiveness associated with hedges related to our butane blending and fractionation activities are recognized currently in earnings as adjustments to product sales.

We also use exchange-traded butane futures agreements, which are not designated as hedges for accounting purposes, to hedge against changes in the price of butane we expect to purchase in the future. Period changes in the fair value of these agreements are recognized currently in earnings as adjustments to cost of product sales.

Additionally, we currently hold petroleum product inventories that we obtained from overages on our pipeline systems. We use NYMEX contracts that are not designated as hedges for accounting purposes to help manage price changes related to these overage inventory barrels. Period changes in the fair value of these agreements are recognized currently in earnings as adjustments to operating expense.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

As outlined in the table below, our open NYMEX contracts and butane futures agreements at December 31, 2013 were as follows:

Type of Contract/Accounting Methodology	Product Represented by the Contract and Associated Barrels	Maturity Dates
NYMEX - Fair Value Hedges	0.7 million barrels of crude oil	Between January 2014 and November 2016
NYMEX - Economic Hedges	2.2 million barrels of refined products and crude oil	Between January and April 2014
Butane Futures Agreements - Economic Hedges	0.1 million barrels of butane	Between January and April 2014

Energy Commodity Derivatives Contracts and Deposits Offsets

At December 31, 2013, we had made margin deposits of $14.8 million for our NYMEX contracts. We have the right to offset the combined fair values of our open NYMEX contracts and our open butane futures agreements against our margin deposits under a master netting arrangement; however, we have elected to disclose the combined fair values of our open NYMEX and butane futures agreements separately from the related margin deposits on our consolidated balance sheets. Additionally, we have the right to offset the fair values of our NYMEX agreements and butane futures agreements together for each counterparty, which we have elected to do, and we report the combined net balances on our consolidated balance sheets. A schedule of the derivative amounts we have offset and the deposit amounts we could offset under a master netting arrangement are provided below as of December 31, 2012 and 2013 (in thousands):

	December 31, 2012				
Description	Gross Amounts of Liabilities	Gross Amounts of Assets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheet	Net Amount
Energy commodity derivatives	$(9,388)	$2,050	$(7,338)	$18,304	$10,966

	December 31, 2013				
Description	Gross Amounts of Liabilities	Gross Amounts of Assets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet(1)	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheet	Net Amount
Energy commodity derivatives	$(7,167)	$2,665	$(4,502)	$14,782	$10,280

(1) Net amount includes energy commodity derivative contracts classified as current liabilities, net, of $6,737 and noncurrent assets of $2,235.

Impact of Derivatives on Income Statement, Balance Sheet and AOCL

At December 31, 2012 and 2013, we had open NYMEX contracts on 0.7 million barrels of crude oil that were designated as fair value hedges. During 2012, because there was no ineffectiveness recognized on these hedges, the cumulative losses of $5.7 million from the agreements were fully offset by a cumulative increase of $5.5 million to tank bottom inventory and an increase of $0.2 million to other current assets; therefore, there was no net impact from these agreements on income/expense. During 2013, because there was no ineffectiveness recognized on these hedges, the cumulative losses of $8.7 million from the agreements were fully offset by a cumulative increase of $8.9 million to tank bottom inventory and a decrease of $0.2 million to other current assets; therefore, there was no net impact from these agreements on income or expense.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The following is a summary of the effect on our consolidated statements of income and statements of comprehensive income for the years ended December 31, 2012 and 2013 of the effective portion of derivatives accounted for under ASC 815-30, Derivatives and Hedging—Cash Flow Hedges, that were designated as hedging instruments (in thousands). See Note 7 - Product Sales Revenue for further details regarding the impact of our NYMEX agreements on product sales.

	Year Ended December 31, 2012		
Derivative Instrument	Amount of Gain Recognized in AOCL on Derivative	Location of Gain Reclassified from AOCL into Income	Amount of Gain Reclassified from AOCL into Income
Interest rate contracts	$10,977	Interest expense	$ 164
NYMEX commodity contracts	2,912	Product sales revenue	2,760
Total cash flow hedges	$13,889	Total	$ 2,924

	Year Ended December 31, 2013		
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Gain (Loss) Reclassified from AOCL into Income	Amount of Gain (Loss) Reclassified from AOCL into Income
Interest rate contracts	$(184)	Interest expense	$ 163
NYMEX commodity contracts	(4,560)	Product sales revenue	(4,408)
Total cash flow hedges	$(4,744)	Total	$ (4,245)

There was no ineffectiveness recognized on the financial instruments disclosed in the above tables during the years ended December 31, 2012 and 2013. See Comprehensive Income in Note 2—Summary of Significant Accounting Policies for a roll-forward of the derivative gains included in AOCL for the years ended December 31, 2011, 2012 and 2013. As of December 31, 2013, the net loss estimated to be classified to interest expense over the next twelve months from AOCL is approximately $0.1 million.
The following table provides a summary of the effect on our consolidated statements of income for the years ended December 31, 2012 and 2013 of derivatives accounted for under ASC 815-10-35; Derivatives and Hedging—Overall—Subsequent Measurement, that were not designated as hedging instruments (in thousands):

		Amount of Gain (Loss) Recognized on Derivative Year Ended December 31,	
Derivative Instrument	Location of Gain (Loss) Recognized on Derivative	2012	2013
NYMEX commodity contracts	Product sales revenue	$(36,959)	$(6,189)
NYMEX commodity contracts	Operating expenses	(2,055)	(3,770)
Butane futures agreements	Cost of product sales	1,203	2,682
	Total	$(37,811)	$(7,277)

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The following tables provide a summary of the amounts included on our consolidated balance sheets of the fair value of derivatives accounted for under ASC 815, Derivatives and Hedging, that were designated as hedging instruments as of December 31, 2012 and 2013 (in thousands):

	December 31, 2012			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$473	Energy commodity derivatives contracts, net	$207

	December 31, 2013			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$—	Energy commodity derivatives contracts, net	$146
NYMEX commodity contracts	Other noncurrent assets	2,235	Other noncurrent liabilities	—
	Total	$2,235	Total	$146

The following tables provide a summary of the amounts included on our consolidated balance sheets of the fair value of derivatives accounted for under ASC 815, Derivatives and Hedging, that were not designated as hedging instruments as of December 31, 2012 and 2013 (in thousands):

	December 31, 2012			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$227	Energy commodity derivatives contracts, net	$8,954
Butane futures agreements	Energy commodity derivatives contracts, net	1,350	Energy commodity derivatives contracts, net	227
	Total	$1,577	Total	$9,181

	December 31, 2013			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$48	Energy commodity derivatives contracts, net	$7,021
Butane futures agreements	Energy commodity derivatives contracts, net	382	Energy commodity derivatives contracts, net	—
	Total	$430	Total	$7,021

14. Leases

Leases—Lessee. We lease land, office buildings and terminal equipment at various locations to conduct our business operations. During 2013, we also entered into contracts to lease pipeline capacity, primarily to accommodate the additional barrels from our Longhorn crude oil pipeline. Several of the agreements provide for negotiated renewal options and cancellation penalties, some of which include the requirement to remove our pipeline from the property for non-performance. Management expects that we will generally renew our expiring leases. Leases are evaluated at inception or at any subsequent material modification and, depending on the lease terms, are classified as either capital or operating leases, as appropriate under ASC 840, Leases. We recognize rent expense on a straight-line basis over the life of the lease. Total rent expense was \$4.6 million, \$4.8 million and

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

$12.0 million for the years ended December 31, 2011, 2012 and 2013, respectively. Future minimum annual rentals under non-cancellable operating leases with initial or remaining terms greater than one year as of December 31, 2013, were as follows (in millions):

2014	$16.2
2015	16.5
2016	16.1
2017	16.6
2018	13.1
Thereafter	51.5
Total	$130.0

Leases—Lessor. We have entered into capacity and storage leases with our customers with remaining terms from one to 20 years that are accounted for as operating-type leases. All of the agreements provide for negotiated extensions. Future minimum payments receivable under these arrangements as of December 31, 2013, were as follows (in millions):

2014	$240.8
2015	229.7
2016	174.6
2017	111.7
2018	71.3
Thereafter	170.5
Total	$998.6

15.Long-Term Incentive Plan

Plan Description

We have a long-term incentive plan (“LTIP”) covering certain of our employees and directors of our general partner. The LTIP primarily consists of phantom units and permits the grant of awards covering an aggregate of 9.4 million of our limited partner units. The remaining units available under the LTIP at December 31, 2013 total approximately 1.8 million. The compensation committee administers our LTIP.

Under our LTIP, the compensation committee has granted performance-based awards and retention awards. Retention awards are subject to forfeiture by a participant if their employment is terminated for any reason other than death or disability prior to the vesting date. Performance-based awards are subject to forfeiture by a participant if their employment is terminated for any reason other than retirement, death or disability prior to the vesting date. If a performance-based award recipient retires, dies or becomes disabled prior to the end of the vesting period, the recipient's award will be prorated based upon the completed months of employment during the vesting period, and the award will be settled shortly after the end of the vesting period. Our agreement with the award participants requires these awards to be paid in our limited partner units. Award grants under our LTIP do not have an early vesting feature except for the performance-based awards which can vest early under certain circumstances following a change in control of our general partner.

For performance-based awards, we base the payout calculation for 80% of the award solely on the attainment of a financial metric established by the compensation committee. We account for this portion of the award grants as equity. The payout calculation for the remaining 20% of the unit awards is based on both the attainment of a

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financial metric and the individual employee's personal performance as determined by the compensation committee. We account for this portion of the award grants as a liability. The payout for the retention awards that have been granted by the compensation committee is subject only to the participant's continued employment with us. We account for these award grants as equity.

Non-Vested Unit Awards

The following table includes the changes during the current fiscal year in the number of non-vested units that have been granted by the compensation committee. The amounts below include no adjustments for above-target or below-target performance and forfeitures are actual amounts through December 31, 2013.

	Equity Method Performance-Based Awards		Retention Awards		Liability Method Performance-Based Awards		Total Awards	
	Number of Unit Awards	Weighted-Average Grant Date Fair Value	Number of Unit Awards	Weighted-Average Grant Date Fair Value	Number of Unit Awards	Weighted-Average Fair Value	Number of Unit Awards	Weighted-Average Fair Value
Non-vested units - 1/1/2013	444,090	$ 31.24	58,802	$ 24.60	111,025	$ 43.19	613,917	$ 32.77
Units granted during 2013	182,798	$ 51.49	22,668	$ 53.02	45,700	$ 51.49	251,166	$ 51.63
Units vested during 2013	(228,058)	$ 29.07	(2,207)	$ 34.02	(57,015)	$ 63.27	(287,280)	$ 35.90
Units forfeited during 2013	(9,420)	$ 35.98	(4,052)	$ 25.00	(2,355)	$ 63.27	(15,827)	$ 37.23
Non-vested units - 12/31/13	389,410	$ 41.90	75,211	$ 32.87	97,355	$ 63.27	561,976	$ 44.40

The table below summarizes the total non-vested unit awards granted by the compensation committee. The award grants have been adjusted for units we estimate will be forfeited by the end of the vesting period and for estimated amounts of above-target financial performance to determine the total number of unit awards included in our total equity-based liability accrual.

Grant Date	Unit Awards Granted	Estimated Forfeitures	Adjustment to Unit Awards in Anticipation of Achieving Above-Target Financial Results	Total Unit Award Accrual	Vesting Date	Unrecognized Compensation Expense[a] (in millions)
Performance-Based Awards:						
2012 Awards	267,322	39,225	228,097	456,194	12/31/2014	$6.0
2013 Awards	228,498	31,869	147,472	344,101	12/31/2015	12.4
Retention Awards:						
2014 Vesting Date	71,849	10,778	—	61,071	12/31/2014	0.7

2015 Vesting Date	444	22	—	422	12/31/2015	—
2016 Vesting Date	13,300	665	—	12,635	12/31/2016	0.7
Total	581,413	82,559	375,569	874,423		$19.8

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Weighted-Average Grant Date Fair Values
The weighted-average grant-date fair value of award grants issued during 2011, 2012 and 2013 were as follows:

	Equity Method				Liability Method	
	Performance-Based Awards		Retention Awards		Performance-Based Awards	
	Number of Unit Awards	Weighted-Average Grant Date Fair Value	Number of Unit Awards	Weighted-Average Grant Date Fair Value	Number of Unit Awards	Weighted-Average Fair Value
Units granted during 2011	281,180	$ 28.52	59,880	$ 23.96	70,296	$ 34.32
Units granted during 2012	214,232	$ 33.57	7,016	$ 30.54	53,558	$ 33.57
Units granted during 2013	182,798	$ 51.49	22,668	$ 53.02	45,700	$ 51.49

Vested Unit Awards

The table below sets forth the numbers and values of units that vested in each of the three years ended December 31, 2013. The vested limited partner units include adjustments for above-target performance.

Vesting Date	Vested Limited Partner Units	Fair Value of Unit Awards on Vesting Date (in millions)*	Intrinsic Value of Unit Awards on Vesting Date (in millions)
12/31/2011	1,100,276	$16.5	$37.9
12/31/2012	751,237	$17.1	$32.5
12/31/2013	572,353	$20.5	$36.2

* Represents the amount of the equity-based liabilities settled in January of the year following the vesting date.

Cash Flow Effects of LTIP Settlements

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

Settlement Date	Number of Limited Partner Units Issued, Net of Tax Withholdings	Minimum Tax Withholdings (in millions)	Employer Taxes (in millions)	Total Cash Taxes Paid (in millions)
January 2011	505,492	$7.4	$0.9	$8.3
January 2012	722,766	$13.0	$1.3	$14.3
January 2013	476,682	$12.3	$1.1	$13.4

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Compensation Expense Summary

Equity-based incentive compensation expense, excluding amounts for directors (discussed below), for 2011, 2012 and 2013 was as follows (in thousands):

	Year Ended December 31, 2011			Year Ended December 31, 2012			Year Ended December 31, 2013		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
2009 awards	$4,418	$4,264	$8,682	$—	$—	$—	$—	$—	$—
2010 awards	3,100	1,562	4,662	4,937	3,723	8,660	121	73	194
2011 awards	2,839	841	3,680	5,062	2,094	7,156	5,359	4,280	9,639
2012 awards	—	—	—	3,426	1,101	4,527	4,751	2,747	7,498
2013 awards	—	—	—	—	—	—	4,726	1,451	6,177
Retention awards	686	—	686	693	—	693	575	—	575
Total	$11,043	$6,667	$17,710	$14,118	$6,918	$21,036	$15,532	$8,551	$24,083
Allocation of LTIP expense on our consolidated statements of income:									
G&A expense			$16,024			$18,587			$23,264
Operating expense			1,686			2,449			819
Total			$17,710			$21,036			$24,083

Director Compensation Expense

Pursuant to our LTIP, long-term incentive awards are granted to independent members of the board of directors of our general partner. Most directors elect to defer all or a portion of their compensation. The table below summarizes the phantom limited partner units earned by our independent directors and total equity-based director compensation expense recognized. The phantom unit and compensation amounts below include amounts credited to the directors' accounts for distribution equivalents earned.

	Year Ended December 31,		
	2011	2012	2013
Phantom units earned pursuant to the LTIP	20,284	20,054	16,424
(in thousands)			
Compensation - phantom unit expense	$446	$523	$533
Distribution equivalents	139	195	267
Changes in market value of phantom units	568	973	2,535
Total value of phantom units	1,153	1,691	3,335
Compensation paid in cash	292	345	422
Compensation paid in our limited partner units	140	170	85
Total director compensation	1,585	2,206	3,842
Distribution equivalents charged to partners' capital	(139)	(195)	(267)

Total director compensation expense	$1,446	$2,011	$3,575

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

16. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. Our segments are managed separately because each segment requires different marketing strategies and business knowledge. Management evaluates performance based on segment operating margin, which includes revenue from affiliates and external customers, operating expenses, cost of product sales and earnings in non-controlled entities. Transactions between our business segments are conducted and recorded on the same basis as transactions with third-party entities. We believe that investors benefit from having access to the same financial measures used by management. Operating margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. Operating margin is not a GAAP measure but the components of operating margin are computed using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the tables below. Operating profit includes depreciation and amortization expense and G&A expenses that management does not consider when evaluating the core profitability of our operations.

	Year Ended December 31, 2011				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
	(in thousands)				
Transportation and terminals revenue	$680,235	$61,205	$151,929	$—	$893,369
Product sales revenue	848,902	591	5,035	—	854,528
Affiliate management fee revenue	—	770	—	—	770
Total revenue	1,529,137	62,566	156,964	—	1,748,667
Operating expenses	250,794	(4,898)	63,438	(2,919)	306,415
Cost of product sales	704,313	—	1,957	—	706,270
Earnings of non-controlled entities	—	(6,761)	(2)	—	(6,763)
Operating margin	574,030	74,225	91,571	2,919	742,745
Depreciation and amortization expense	81,876	10,303	26,081	2,919	121,179
G&A expenses	80,746	1,773	16,150	—	98,669
Operating profit	$411,408	$62,149	$49,340	$—	$522,897
Additions to long-lived assets	$130,645	$45,124	$38,125		$213,894
	As of December 31, 2011				
Segment assets	$2,736,522	$432,073	$638,451		$3,807,046
Corporate assets					237,955
Total assets					$4,045,001
Goodwill	$38,369	$12,082	$2,809		$53,260
Investments in non-controlled entities	$—	$24,936	$10,658		$35,594

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

	Year Ended December 31, 2012				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
	(in thousands)				
Transportation and terminals revenue	$723,835	$92,288	$154,621	$—	$970,744
Product sales revenue	790,116	—	9,266	—	799,382
Affiliate management fee revenue	—	1,734	214	—	1,948
Total revenue	1,513,951	94,022	164,101	—	1,772,074
Operating expenses	267,694	5,229	58,486	(2,955)	328,454
Cost of product sales	653,429	—	3,679	—	657,108
Earnings of non-controlled entities	—	(2,574)	(387)	—	(2,961)
Operating margin	592,828	91,367	102,323	2,955	789,473
Depreciation and amortization expense	86,218	12,228	26,611	2,955	128,012
G&A expenses	87,309	5,420	16,674	—	109,403
Operating profit	$419,301	$73,719	$59,038	$—	$552,058
Additions to long-lived assets	$127,744	$166,960	$56,485		$351,189

	As of December 31, 2012				
Segment assets	$2,530,770	$875,005	$656,855		$4,062,630
Corporate assets					357,437
Total assets					$4,420,067
Goodwill	$38,369	$12,082	$2,809		$53,260
Investments in non-controlled entities	$—	$91,629	$15,727		$107,356

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

	Year Ended December 31, 2013				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
	(in thousands)				
Transportation and terminals revenue	$801,128	$178,409	$158,791	$—	$1,138,328
Product sales revenue	738,271	—	6,398	—	744,669
Affiliate management fee revenue	—	13,361	1,248	—	14,609
Total revenue	1,539,399	191,770	166,437	—	1,897,606
Operating expenses	270,711	19,131	59,407	(3,179)	346,070
Cost of product sales	574,703	—	3,326	—	578,029
Earnings of non-controlled entities	—	(3,781)	(2,494)	—	(6,275)
Operating margin	693,985	176,420	106,198	3,179	979,782
Depreciation and amortization expense	86,926	24,119	28,006	3,179	142,230
G&A expenses	91,658	19,896	20,942	—	132,496
Operating profit	$515,401	$132,405	$57,250	$—	$705,056
Additions to long-lived assets	$361,134	$199,362	$32,563		$593,059
	As of December 31, 2013				
Segment assets	$2,811,398	$1,252,036	$648,061		$4,711,495
Corporate assets					109,317
Total assets					$4,820,812
Goodwill	$38,369	$12,082	$2,809		$53,260
Investments in non-controlled entities	$—	$345,904	$14,948		$360,852

17. Commitments and Contingencies

Clean Air Act - Section 185 Liability

Section 185 of the Clean Air Act ("CAA 185") requires states to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas that did not meet the attainment deadline. The CAA 185 fees are required annually until the area is redesignated as an attainment area for ozone. The Houston-Galveston region was determined to be a severe nonattainment area that did not meet its 2007 attainment deadline and, as such, would be subject to CAA 185.

During 2011, the Texas Commission on Environmental Quality (“TCEQ”) had published notices concerning its intention to issue a “Failure to Attain Rule” to implement the requirements of CAA 185. At that time, management believed it was probable that the TCEQ’s Failure to Attain Rule would provide for the collection of annual failure to attain fees for excess emissions for the annual periods from 2008 through 2011. We have certain facilities in the Houston area that would have been subject to these rules; therefore, we recognized a $10.9 million environmental liability during 2011 as our estimate of excess emission fees we would be required to pay under the rules.

In June 2013, the TCEQ adopted its Failure to Attain Rule which did not require retroactive assessment of the Section 185 fees for the annual periods of 2008 through 2011. As a result, during 2013, in accordance with the TCEQ's final rule, we reduced our accrual by $10.6 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Environmental Liabilities

Liabilities recognized for estimated environmental costs were $48.3 million and $38.5 million at December 31, 2012 and December 31, 2013, respectively. We have classified environmental liabilities as current or noncurrent based on management’s estimates regarding the timing of actual payments. Management estimates that expenditures associated with these environmental liabilities will be substantially paid over the next 10 years. Environmental expenses recognized as a result of changes in our environmental liabilities are included in operating expenses on our consolidated statements of income. Environmental expenses were $23.1 million, $12.0 million and $(5.2) million for the years ended December 31, 2011, 2012 and 2013, respectively. The higher environmental expense in 2011 was primarily due to the CAA 185 liability accrual and the lower environmental expense for 2013 was primarily due to the $10.6 million favorable adjustment to this accrual, both of which are discussed above.

Environmental Receivables

Receivables from insurance carriers and other third parties related to environmental matters at December 31, 2012 were $7.9 million, of which $2.8 million and $5.1 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheet. Receivables from insurance carriers related to environmental matters at December 31, 2013 were $4.8 million, of which $2.1 million and $2.7 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheet. Amounts received from insurance carriers and other third parties related to environmental matters during 2011, 2012 and 2013 were $0.5 million, $1.2 million and $4.2 million, respectively.

Other

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

18. Quarterly Financial Data (unaudited)

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

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2012	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$493,483	$449,527	$325,869	$503,195
Total costs and expenses	$372,318	$283,724	$248,334	$318,601
Operating margin	$178,067	$224,181	$138,527	$248,698
Net income	$93,524	$137,821	$50,522	$153,803
Basic and diluted net income per limited partner unit	$0.41	$0.61	$0.22	$0.68
2013				
Revenue	$432,421	$443,912	$443,835	$577,438
Total costs and expenses	$291,967	$260,191	$291,586	$355,081
Operating margin	$208,893	$251,905	$222,649	$296,335
Net income	$112,967	$153,640	$125,623	$190,007
Basic net income per limited partner unit	$0.50	$0.68	$0.55	$0.84
Diluted net income per limited partner unit	$0.50	$0.68	$0.55	$0.83

In mid-April 2013, we began making deliveries of crude oil from our Longhorn pipeline, which significantly benefited our operations. Further, during 2013, we completed the acquisition of the New Mexico/Texas and Rocky Mountain pipeline systems from Plains, which benefited our results of operations for the year, particularly in the fourth quarter. Also, second quarter 2013 results were benefited by the $10.6 million accrual reversal related to the Section 185 CAA liability (see Note 17--Commitments and Contingencies for further discussion of this matter).

19. Fair Value Disclosures

Fair Value Methods and Assumptions - Financial Assets and Liabilities

We used the following methods and assumptions in estimating fair value for our financial assets and liabilities:

- Cash and cash equivalents. Cash equivalents include money market and mutual fund accounts and commercial paper. The carrying amounts reported on our consolidated balance sheets approximate fair value due to the short-term maturity or variable rates of these instruments.

- Energy commodity derivatives deposits. This asset represents short-term deposits we have made associated with our energy commodity derivatives contracts. The carrying amount reported on our consolidated balance sheets approximates fair value as the deposits change daily in relation to the associated contracts which are held in separate accounts.

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

- Long-term receivables. These are primarily insurance receivables, whose fair value was determined by estimating the present value of future cash flows using a risk-free rate of interest derived from U.S. treasury rates.

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Debt. The fair value of our publicly traded notes was based on the prices of those notes at December 31, 2012 and 2013; however, where recent observable market trades were not available, prices were determined using adjustments to the last traded value for that debt issuance or by adjustments to the prices of similar debt instruments of peer entities that are actively traded. The carrying amount of borrowings, if any, under our revolving credit facility approximates fair value due to the variable rates of that instrument.

Fair Value Measurements - Financial Assets and Liabilities

The following tables summarize the carrying amounts, fair values and recurring fair value measurements recorded or disclosed as of December 31, 2012 and 2013, based on the three levels established by ASC 820; Fair Value Measurements. The carrying values of cash and cash equivalents (classified as Level 1) and energy commodity derivatives deposits approximate fair value because of the short-term nature or variable rates of these instruments; therefore, these items are not presented in the following tables (in thousands):

			Fair Value Measurements as of December 31, 2012 using:		
Assets (Liabilities)	Carrying Amount	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivatives contracts (liabilities)	$(7,338)	$(7,338)	$(7,338)	$—	$—
Long-term receivables	$5,135	$5,108	$—	$—	$5,108
Debt	$(2,393,408)	$(2,721,985)	$(2,721,985)	$—	$—

			Fair Value Measurements as of December 31, 2013 using:		
Assets (Liabilities)	Carrying Amount	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivatives contracts (liabilities)	$(4,502)	$(4,502)	$(4,502)	$—	$—
Long-term receivables	$2,730	$2,658	$—	$—	$2,658
Debt	$(2,685,287)	$(2,815,210)	$—	$(2,815,210)	$—

During 2013, we re-evaluated the market in which our debt securities trade. Based on that review, we determined that this market no longer included sufficient market activity to qualify as an active market, as defined in ASC 820, Fair Value Measurements. As a result, we transferred the hierarchical reporting level of the fair value measurement of our debt securities from Level 1 to Level 2. Our policy is to effect transfers between hierarchical reporting levels at the end of the reporting period where it has been determined that a change is required.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

20. Distributions

Distributions we paid during 2011, 2012 and 2013 were as follows (in thousands, except per unit amount):

Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution
2/14/2011	$0.37875	$85,398
5/13/2011	0.38500	86,807
8/12/2011	0.39250	88,498
11/14/2011	0.40000	90,189
Total	$1.55625	$350,892
2/14/2012	$0.40750	$92,177
5/15/2012	0.42000	95,004
8/14/2012	0.47125	106,597
11/14/2012	0.48500	109,707
Total	$1.78375	$403,485
2/14/2013	$0.50000	$113,340
5/15/2013	0.50750	115,040
8/14/2013	0.53250	120,707
11/14/2013	0.55750	126,374
Total	$2.09750	$475,461

21.Owners’ Equity

The following table details the changes in the number of our limited partner units outstanding from January 1, 2011 through December 31, 2013:

Limited partner units outstanding on January 1, 2011	224,962,698
01/11—Settlement of 2008 award grants	505,492
01/11—Other[(a)]	4,952
Limited partner units outstanding on December 31, 2011	225,473,142
01/12—Settlement of 2009 award grants	722,766
01/12—Other[(a)]	4,964
Limited partner units outstanding on December 31, 2012	226,200,872
01/13—Settlement of 2010 award grants	476,682
01/13—Other[(a)]	1,884
Limited partner units outstanding on December 31, 2013	226,679,438

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

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

Limited partners holding our limited partner units have the following rights, among others:

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

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

22. Subsequent Events

Recognizable events

No recognizable events have occurred subsequent to December 31, 2013.

Non-recognizable events

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On February 3, 2014, 178,184 phantom unit awards were issued pursuant to our long-term incentive plan. These grants included both performance-based and retention awards and have a three-year vesting period that will end on December 31, 2016.

On February 3, 2014, we issued 388,819 limited partner units, of which 387,216 were issued to settle unit award grants to certain employees that vested on December 31, 2013 and 1,603 were issued to settle the equity-based retainer paid to one of the directors of our general partner.

On February 14, 2014, we paid cash distributions of $0.585 per unit on our outstanding limited partner units to unitholders of record at the close of business on February 7, 2014. The total distributions paid were $132.8 million.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We performed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rule 13a-14(c) of the Securities Exchange Act) as of the end of the period covered by the date of this report. We performed this evaluation under the supervision and with the participation of our management, including our general partner's Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner's Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and practices are effective in providing reasonable assurance that all required disclosures are included in the current report. There have been no changes in our internal control over financial reporting (as defined in Rule 13a - 15(f) of the Securities Exchange Act) during the quarter ending December 31, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

Management's Report on Internal Control Over Financial Reporting

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

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance
The information regarding the directors and executive officers of our general partner and our corporate governance required by Items 401, 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K will be presented in our definitive proxy statement to be filed pursuant to Regulation 14A (our “Proxy Statement”) under the following captions, which information is to be incorporated by reference herein:

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

Item 11. Executive Compensation
The information regarding executive compensation required by Items 402 and 407(e)(4) and (e)(5) of Regulation S-K will be presented in our Proxy Statement under the following captions, which information is to be incorporated by reference herein:

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

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters
The information regarding securities authorized for issuance under equity compensation plans and security ownership required by Items 201(d) and 403 of Regulation S-K will be presented in our Proxy Statement under the following captions, which information is to be incorporated by reference herein:

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

Item 13. Certain Relationships and Related Transactions, and Director Independence
The information regarding certain relationships and related transactions and director independence required by Items 404 and 407(a) of Regulation S-K will be presented in our Proxy Statement under the following captions, which information is to be incorporated by reference herein:

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

Item 14. Principal Accountant Fees and Services
The information regarding principal accountant fees and services required by Item 9(e) of Schedule 14A of the Securities Exchange Act of 1934 will be presented in our Proxy Statement under the caption “Independent Registered Public Accounting Firm,” which information is to be incorporated by reference herein.

PART IV

Exhibits and Financial Statement Schedules
(a)1 and (a)2.

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

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

Exhibit No.	Description
Exhibit 3	
*(a)	Certificate of Limited Partnership of Magellan Midstream Partners, L.P. dated August 30, 2000, as amended on November 15, 2002 and August 12, 2003 (filed as Exhibit 3.1 to Form 10-Q filed November 10, 2003).
*(b)	Fifth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated September 28, 2009 (filed as Exhibit 3.1 to Form 8-K filed September 30, 2009).
*(c)	Amendment No. 1 dated October 27, 2011 to Fifth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated September 28, 2009 (filed as Exhibit 3.1 to Form 8-K filed October 28, 2011).
*(d)	Amended and Restated Certificate of Formation of Magellan GP, LLC dated November 15, 2002, as amended on August 12, 2003 (filed as Exhibit 3(f) to Form 10-K filed March 10, 2004).
*(e)	Third Amended and Restated Limited Liability Company Agreement of Magellan GP, LLC dated September 28, 2009 (filed as Exhibit 3.2 to Form 8-K filed September 30, 2009).
Exhibit 4	
*(a)	Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed May 25, 2004).
*(b)	First Supplemental Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.2 to Form 8-K filed May 25, 2004).

*(c)	Second Supplemental Indenture dated as of October 15, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed October 15, 2004).
*(d)	Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed April 20, 2007).
*(e)	First Supplemental Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed April 20, 2007).
*(f)	Second Supplemental Indenture dated as of July 14, 2008 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed July 14, 2008).
*(g)	Third Supplemental Indenture dated as of June 26, 2009 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed June 26, 2009).

Exhibit No.	Description
*(h)	Indenture dated as of August 11, 2010 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed August 16, 2010).
*(i)	First Supplemental Indenture dated as of August 11, 2010 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed August 16, 2010).
*(j)	Second Supplemental Indenture dated as of November 9, 2012 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed November 9, 2012).
*(k)	Third Supplemental Indenture dated as of October 10, 2013 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed October 10, 2013).
Exhibit 10	
*(a)	Amended and Restated Magellan Midstream Partners Long-Term Incentive Plan dated January 22, 2013 (filed as Exhibit 10(a) to Form 10-K filed February 22, 2013).
(b)	Description of Magellan 2014 Annual Incentive Program.
(c)	Magellan GP, LLC Non-Management Director Compensation Program effective January 1, 2014.
(d)	Amended and Restated Director Deferred Compensation Plan effective January 28, 2014.
*(e)	$800,000,000 Credit Agreement dated as of October 27, 2011 among Magellan Midstream Partners, L.P., the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent and an Issuing Bank, JPMorgan Chase Bank, N.A., as Co-Syndication Agent and an Issuing Bank, and Suntrust Bank, as Co-Syndication Agent and an Issuing Bank (filed as Exhibit 10.1 to Form 8-K filed October 28, 2011).
*(f)	First Amendment to Credit Agreement, dated as of November 21, 2013, among Magellan Midstream Partners, L.P., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to Form 8-K filed November 22, 2013).
*(g)	Executive Severance Pay Plan dated July 21, 2011 (filed as Exhibit 10.2 to Form 10-Q filed August 4, 2011).
(h)	Form of 2014 Phantom Unit Agreement for awards granted pursuant to the Magellan Midstream Partners Long-Term Incentive Plan.
Exhibit 12	Ratio of earnings to fixed charges.
Exhibit 14	
*(a)	Code of Ethics dated February 1, 2011 by Michael N. Mears, principal executive officer (filed as Exhibit 14(a) to Form 10-K filed February 25, 2011).

*(b)	Code of Ethics dated February 1, 2011 by John D. Chandler, principal financial and accounting officer (filed as Exhibit 14(b) to Form 10-K filed February 25, 2011).
Exhibit 21	Subsidiaries of Magellan Midstream Partners, L.P.
Exhibit 23	Consent of Independent Registered Public Accounting Firm.
Exhibit 31	
(a)	Certification of Michael N. Mears, principal executive officer.
(b)	Certification of John D. Chandler, principal financial officer.
Exhibit 32	
(a)	Section 1350 Certification of Michael N. Mears, Chief Executive Officer.
(b)	Section 1350 Certification of John D. Chandler, Chief Financial Officer.
Exhibit 101.INS	XBRL Instance Document.
Exhibit 101.SCH	XBRL Taxonomy Extension Schema.
Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase.
Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase.
Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

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

SIGNATURES

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

MAGELLAN MIDSTREAM PARTNERS, L.P.
(Registrant)

By: MAGELLAN GP, LLC, its general partner

By: /s/ JOHN D. CHANDLER
John D. Chandler
Senior Vice President
and Chief Financial Officer

Date: February 24, 2014

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

Signature	Title	Date
/s/ MICHAEL N. MEARS Michael N. Mears	Chairman of the Board and Principal Executive Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2014
/s/ JOHN D. CHANDLER John D. Chandler	Principal Financial and Accounting Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2014
/s/ WALTER R. ARNHEIM Walter R. Arnheim	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2014
/s/ ROBERT G. CROYLE Robert G. Croyle	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2014
/s/ PATRICK C. EILERS Patrick C. Eilers	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2014
/s/ JAMES C. KEMPNER James C. Kempner	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2014
/s/ JAMES R. MONTAGUE James R. Montague	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2014
/s/ BARRY R. PEARL		February 24, 2014

	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.
Barry R. Pearl	

Index to Exhibits

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